Docket Nos. 2019-185-E and 2019-186-E

Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62

Prepared for:

Public Service Commission of South Carolina

November 1, 2019

Submitted by:

John Dalton,
President
Power Advisory LLC
212 Thoreau Street
Concord, MA 01742
(978) 369-2465
poweradvisoryllc.com

Executive Summary

Introduction

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power. These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[1]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. The main areas of review and analysis are avoided costs; variable integration charges and appropriate PPA terms and conditions. Each is reviewed below.

Avoided Costs

The Companies stressed the risk of overpayment from long-term PPAs based on avoided costs, noting that the 4,000 MWs of solar QF PPAs under contract represent an overpayment of about $2.26 billion at current avoided costs, a figure that intervenors say was overstated. Other parties indicated that overpayment risk is mitigated going forward since avoided costs will be updated every two years. Intervenors also said that ratepayers don't bear the risk of cost overruns with QFs, unlike with utility owned generation.

Parties discussed whether avoided costs might go up or down in the future thus either benefiting or harming ratepayers given the long-term contracts with QFs at a fixed price based on these avoided costs. The primary factor of future avoided costs was identified as natural gas prices, with intervenors saying gas prices are likely to increase substantially.

[1] Act 62. Section 58-41-20. (A)

Avoided Energy Costs

The Companies use the peaker methodology to estimate avoided costs, which is a widely accepted industry standard.

Areas of investigation with respect to the Companies' avoided energy costs included the following:

- Negative Avoided Energy Costs
- Coal Unit Retirements
- DEP East and DEP West Integration
- Selection of Avoided Cost Periods

Avoided Capacity Costs

Areas of investigation regarding the Companies' avoided capacity cost estimates in our report included the following:

- Assessment of Avoided Capital Cost Methodology
- Capital Cost of a New Peaker
- Capacity Value Timing, where we recommend an advancement of the first year of need for additional capacity given recently announced coal unit retirements.
- Weighting of Peak Periods, where we recommend increasing the weight given to the summer peak period.

Solar Integration Services Charge (SISC)

The Companies' proposed SISC and the methodology employed to develop it were the subject of considerable dispute among the parties. However, prior to the commencement of the hearings, various parties submitted a partial settlement agreement covering the SISC. The agreed upon charges were $1.10/MWh for DEC and $2.39/MWh for DEP.

PPA and NOC Terms and Conditions

Power Advisory discussed the concept of commercial reasonableness as it relates to the Power Purchase Agreements and Notice of Commitment to Sell Forms. We also discussed the implications of a 10-year contract term identified in Act 62.

In the course of this proceeding, the two sides (namely the Companies and SBA) came to agreement on many matters which Power Advisory found to be fair and reasonable. The matters that were unresolved were as follows:

Standard Offer PPA issues not resolved include:

- Material alterations - retroactive vs. prospective

- 30-month in-service date following rates approval

Large QF PPA issues not resolved include:

- Facilities Study Agreement (FSA) a condition of signing a Large QF PPA
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC
- Surety Bonds as a permissible form of performance assurance

Notice of Commitment (NOC) to Sell Form issues not resolved include:

- All required permits and land-use approvals a condition of LEO formation
- 365 day in-service requirement following LEO formation
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC

For each of these issues, Power Advisory provided a summary of the positions of both sides and provided its independent opinion to the Commission based on the evidence provided.

Table of Contents

1. INTRODUCTION

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). PURPA was originally enacted by the US Congress in 1978.[2] There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power. (See discussion in Chapter 2.) These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62. QFs include small power producers that utilize renewable energy to generate electricity and are 80 MW or smaller as well as cogeneration facilities.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[3]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. Standard offers are employed to recognize that small projects are less able than large projects to bear the costs associated with negotiating a PPA and ascertaining the terms and conditions under which the local electric utility would be willing to purchase power.

Act 62 applies to all utilities that are regulated by the Commission, except that electric utilities serving less than 100,000 customers are exempt from the renewable energy programs outlined in Chapter 41 of the Act. As such, the Act applies to Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), collectively the "Companies" or "Duke"; and Dominion Energy South Carolina, Inc. (DESC). Pursuant to Act 62 the Commission opened three dockets for the three

---

[2] On September 19, 2019, FERC issued a Notice of Proposed Rulemaking on Qualifying Facility Rates and Requirements and Implementation Issues Under PURPA (NOPR), which proposes to scale back some of the requirements of PURPA. FERC characterizes the intent of the NOPR to "rebalance the benefits and obligations of the Commission's PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated in 1980." (para 4.) Power Advisory notes that the Commission's actions in these dockets are in response to Act 62, but that Section 58-41-10 (B) does specify that "implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that: …power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."

This is only a notice of proposed rulemaking, which should not be interpreted as the promulgation of final regulations.

[3] Act 62. Section 58-41-20. (A)

utilities to which the Act applies, for DESC Docket No. 2019-184-E, DEC Docket No. 2019-185-E, and DEP Docket No. 2019-186-E.

With respect to implementing the Act, the Commission is directed:

> "to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The commission also is directed to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of this act."[4]

The Act requires Commission decisions to reflect a careful balancing of interests:

> "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."

Further guidance regarding how the interests of QFs will be protected and balanced with customers' interests flows from the direction to:

> "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:
>
> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
>
> (2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
>
> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy,

[4] Act 62. Section 58-41-05.

capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."

Act 62 also authorizes the commission "to employ, through contract or otherwise, third party consultants and experts in carrying out its duties under this section, including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions under this section."[5] Power Advisory LLC (Power Advisory) was engaged by the Commission on September 3rd to serve as the independent third-party consultant in the three dockets filed pursuant to Act 62. This is Power Advisory's report to the Commission outlining our findings from the review of the materials filed by the parties and the hearings before the Commission regarding DEC and DEP in Docket Nos. 2019-185-E and 2019-186-E.

1.1 Relevant Experience of Power Advisory

Power Advisory is a management consulting firm focused on the North American electricity sector. The lead consultant on this project and Power Advisory President, John Dalton, has over thirty years of experience as a senior electricity market analyst and policy consultant. John has testified in over 25 proceedings before state and provincial regulatory commissions; advised jurisdictions on the design of renewable energy procurement frameworks including standard offer programs; and has extensive experience overseeing and reviewing quantitative analyses including avoided cost estimates, electricity price forecasts, generation technology cost estimates and production cost modeling.

Recent Power Advisory consulting assignments related to the mandate of South Carolina Act 62 include drafting and review of Power Purchase Agreements for renewable energy resources including variable output resources such as solar; assessing renewable technology costs; evaluating the requirements to integrate variable output renewable energy resources and reviewing utility avoided costs. Power Advisory has overseen the development, reviewed the implementation, and advised on changes to renewable energy procurement programs in Alberta, British Columbia, Massachusetts, New York, Nova Scotia, Ontario, Rhode Island and Vermont. For some of these projects, Power Advisory was responsible for drafting the Power Purchase Agreement. While serving as the Nova Scotia Renewable Energy Administrator, Power Advisory drafted the PPA which was accepted by the Utility and Review Board. Relevant to the consideration of variable energy integration charges, Power Advisory prepared a report for the Government of Canada on the integration of variable output renewable energy sources focusing on the importance of essential reliability services. Power Advisory team members have a long history of running and overseeing the specification of production cost models (and reviewing the results of these models) such as the Companies used to develop their avoided cost estimates.

---

[5] Act 62. Section 58-41-20. (H)

1.2 Power Advisory Review and Participation in Proceeding

As indicated, Power Advisory was engaged by the Commission on September 3, 2019. Hearings in these proceedings began on October 21st after the parties submitted Direct, Rebuttal and Surrebuttal Testimony. Power Advisory issued interrogatories and requests for production of documents to the Companies, reviewed the interrogatory responses and documents provided by the parties as well as reviewed the filed Direct, Rebuttal and Surrebuttal Testimony and monitored the hearings. Given the schedule in this proceeding which requires a Commission decision by November 16th, we were requested by the Commission to issue a final report on or before November 4th to provide the parties an opportunity to comment on the report.

Act 62 specifies that "the qualified independent third party's duty will be to the commission. Any conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding, to inform its ultimate decision setting the avoided costs for each electrical utility."[6] We have sought to follow this direction and ensure that our conclusions are based on the evidence in the record. We note that the schedule for this proceeding was compressed and this is the first opportunity for us to present our findings. Where necessary and appropriate we rely on our expertise in the electricity sector to evaluate and analyze the findings and information presented by the parties.

1.3 Contents of the Report

Our report is organized along the primary areas of focus of Act 62. Following this introduction is our review of the definition of avoided costs, a discussion of potential risks from avoided cost-based rates, a review of the avoided cost methodology proposed and the resulting avoided cost estimates and response to major issues regarding these avoided cost estimates identified by parties to this proceeding. The next chapter reviews the Companies' proposed Solar Integration Services Charges, the methodology that was used to develop these charges and the partial settlement agreement entered into by various parties. Chapter 4 reviews various terms and conditions that are disputed by the parties pertaining to the power purchase agreements and notice of commitment to sell forms.

Act 62 provides that "The independent third party shall also include in the report a statement assessing the level of cooperation received from the utility during the development of the report and whether there were any material information requests that were not adequately fulfilled by the electrical utility."[7] Power Advisory notes that the Companies provided a high level of cooperation and were responsive to Power Advisory requests.

---

[6] Act 62. Section 58-41-20. (I)

[7] Act 62. Section 58-41-20. (H)

2. STANDARD OFFER AND AVOIDED COST METHODOLOGIES

2.1 Defining Avoided Costs

Act 62 defines "avoided cost" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source".[8] As Duke Witness Snider notes, this is "precisely the same definition prescribed by the Federal Energy Regulatory Commission's ("FERC") implementing regulations."[9]

The Act also directs that:

> "each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."[10]

2.2 Perspective on Avoided Cost Risks

DEC/DEP highlight the risks posed by establishing avoided costs that in hindsight overstate these incremental energy and capacity costs.

In his Direct Testimony, Duke Witness George V. Brown notes the "over-payment risk" associated with allowing QFs to lock in long-term administratively-determined avoided costs has been part of a broader national conversation regarding PURPA implementation, with the National Association of Regulatory Utilities Commissioners ("NARUC") recently advocating in a letter to FERC that calculating avoided costs should "move away from the use of administratively determined avoided costs to their measurement through competitive solicitations or market clearing prices."[11] He then notes that the "the avoided cost rates paid to QFs in substantially all of the PPAs associated with the almost 4,000 MW of solar QF power is now in excess of the Companies' current avoided cost."[12] This overpayment represents about $2.26 billion at the

---

[8] 16. U.S.C. Section 824a-3(b); (d).

[9] Duke Snider Direct, p. 5.

[10] Act 62. Section 58-41-20 (B) (3).

[11] Duke Brown Direct, p. 12-13.
National Association of Regulatory Utility Commissioners December 18, 2017 Letter to Federal Energy Regulatory Commission, Re: Public Utility Regulatory Policies Act of 1978 Regulatory Reform, at 2, accessible at:
https://www.naruc.org/about-naruc/press-releases/naruc-pushes-for-purpa-reform-in-letterto- ferc/

[12] Duke Brown Direct, p. 16, line 7.

Companies' current avoided costs, or about 48% of the financial obligation represented by these PPAs.[13]

SBA argued and Power Advisory concurs that this calculation of the overpayment overstates the reduction in value of the energy and capacity provided by these QFs because the addition of this 4,000 MW of QF power contributes to the reduction in avoided costs.[14] Specifically, the value of avoided capacity for DEC has been reduced from about $6.68/MWh to $0.83/MWh in large part because these solar QF additions have changed when the system peak is likely to occur and the resulting peak load reductions provided by solar QFs.[15] The Companies noted that this is the nature of any resource: the more you add, the less it's worth.[16] Ultimately, the Companies asserted that a small part of the roughly $30/MWh decline in avoided costs that they cite is attributable to the impact of additional solar in reducing the avoided costs attributable to solar.[17]

Mr. Snider notes that "there are three primary components that contribute to the overpayment risk for customers under PURPA: (1) avoided cost rates, (2) length of contract, and (3) the volume of contracts."[18] Power Advisory notes that the avoided costs proposed by DEP and DEC in Dockets 2019-185-E and 2019-186-E are significantly less than those that contributed to this above market cost that the Companies raise as an example of overpayment risk. As discussed further below, the relatively low level of current avoided cost rates mitigate future over-payment risks. Conversely, Mr. Burgess and Mr. Davis assert that there are risks and uncertainties associated with the utilities' avoided cost estimates and available resource options that also need to be considered and weighed. Mr. Burgess asserts that there are risks of "cost overruns of large traditional resource procurements"[19] and "stranded costs for 20- to 40-year capital-intensive traditional infrastructure investments".[20] Mr. Burgess argues that thermal plants had larger and more often experienced cost overruns than solar projects. Whereas Mr. Burgess notes that with PURPA-based contracts ratepayers don't bear any cost overrun risk.[21] Power Advisory notes that new projects built by the Companies will likely be built under the traditional regulatory construct where prudently incurred

[13] The Companies acknowledge that these avoided costs have not been approved by the Commission. Hearing Vol. 1, p. 59, lines 12-15 (Duke Brown).

[14] Hearing Vol. 1, p. 57, lines 3-7 (Duke Snider).

[15] Ibid., p. 66 lines 7-9.

[16] Ibid., p. 70 lines 21-24.

[17] Ibid., p. 71, lines 8-14.

[18] Duke Snider Direct, p.16, lines 11-13.

[19] SBA Burgess Direct, p.13, lines 20-21.

[20] Ibid., p. 14, lines 17-18.

[21] Ibid., p. 17, lines 8-9.

costs can be recovered from customers. This can result in customers paying higher project costs than the utility estimate, which presumably would not be embedded in the utilities' avoided costs projections. Conversely, if the project's construction cost is less than the estimate these savings would be shared by customers. However, an important difference with respect to QFs is that their cost recovery is based on avoided costs that would be fixed for the contract term. However, risks can increase with increases in the volume of purchases.

Power Advisory notes that the risks of the utilities' projections of avoided costs significantly overstating actual avoided costs over the terms of any power purchase agreements entered into by QFs are mitigated by the direction in the Act that fixed price obligations be based on a 10-year avoided cost determination.[22,23] Another mitigant to the risk of avoided costs significantly overstating actual avoided costs are relatively low natural gas prices, with the average cost of ten-year forward natural gas declining about 25 percent between 2015 and 2019.[24] **Figure 1** shows the decline in natural gas prices from 2015 to 2019. In his Direct Testimony, Mr. Snider notes that for DEP and DEC "natural gas commodity prices represent the primary driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource."[25]

Yet another mitigant to the risk of avoided costs significantly overstating actual avoided costs is the fact that avoided costs are to be updated every two years pursuant to the Act and that the Commission could open a proceeding to update avoided costs prior to this if deemed necessary.[26] While this doesn't affect the risks posed by any PPAs awarded through the standard offer program prior to the reset, it does limit the risk going forward. Such a re-evaluation of avoided costs every two years is consistent with best practice.

[22] Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. Section 58-41-20. (F) (1) This issue is discussed further below.

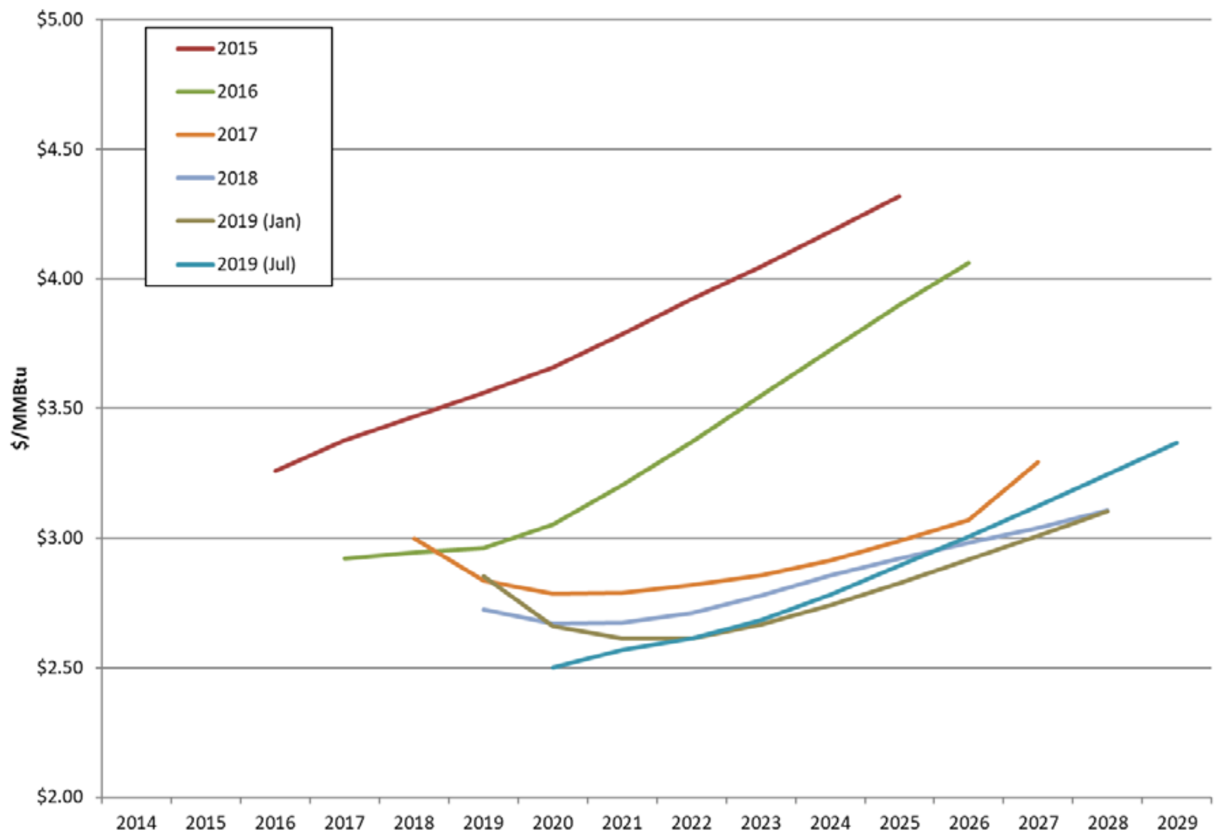
[23] The Act does indicate that the "commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." Section 58-41-20. (F) (1)

[24] Hearing, Vol 1, p. 47, lines 14-16 (Duke Snider)

[25] Duke Snider Direct, p. 24.

[26] Hearing, Vol 1, p. 179, lines 11-21 (Duke Brown)

Figure 1: 10-Year Forward Market Natural Gas Prices (Period 2015 to July 2019)[27]



2.3 Rate Impacts

The Companies have pointed out the overpayment risks and the resulting rate impacts from avoided cost projections that prove to be higher than actual avoided costs incurred. The magnitude of these risks was the subject of considerable discussion and dispute among the parties. With the Companies pointing out past experience which has resulted in significant overpayments to QFs and the SBA and JDA noting that the avoided cost estimates that are the subject of this proceeding are considerably below previous estimates and that this reduces the risks of avoided costs that prove to be too high. In general, there was some agreement among the intervenors that accurate avoided cost projections avoid this overpayment risk and any resulting adverse rate impacts over the long-term because the avoided costs paid to QFs would

[27] Duke Snider Direct, p. 24.

by definition reflect the utilities' cost to generate or purchase this power.[28,29] Forecasts are inevitability wrong so that actual realized avoided costs will be either higher or lower than the projections.

An important determinant of this avoided cost risk are future natural gas prices and the degree to which they depart from the values reflected in the Companies' filed avoided cost projections. As indicated in Figure 1 above, there was general agreement that natural gas prices are at what some parties characterized as historic lows. This caused some parties, including Office of Regulatory Staff witness Mr. Horii, to argue that there's a greater risk of higher natural gas prices and ultimately higher avoided costs than a risk of lower natural gas prices and lower avoided costs.[30] Ms. Chilton argued that the potential benefits of locking in lower QF purchase prices now is greater than the potential risk.[31]

2.4 Transparency of Avoided Cost Filing

Act 62 specifies that "Each electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[32] In this section, Power Advisory assesses the transparency of DEC and DEP's avoided cost filing. We note that the language in this section of the Act references the utility's avoided cost filing. DEC and DEP included as a confidential exhibit in the Direct Testimony of Glen A. Snider "supporting calculations used to derive the avoided energy and avoided capacity rates." While improvements can be made in subsequent biennial avoided cost filings, Power Advisory believes that DEC and DEP's avoided cost filing and subsequent responses to data requests and requests for production of documents resulted in an avoided cost filing that was reasonably transparent.

In his Rebuttal Testimony, Mr. Horii testifying on behalf of the Office of Regulatory Staff noted "The Companies provided data responses and supporting information to their filings that allowed me to conduct my analysis, assess the reasonableness of their proposals, and develop recommendations regarding the implementation of Act 62."[33] He also noted that "While I was able

---

[28] With avoided costs levelized over ten years, there can be some rate impacts initially as the fixed rate paid to the QF may be higher than the actual avoided cost in the initial years of the PPA. Over the life of the PPA with accurate avoided cost projects there would be offsetting savings in the later years in the contract term.

[29] Hearing Vol 2, p. 89 (ORS Horii) and ORS Horii Surrebuttal, p.8.

[30] Hearing Vol 2, p. 92-93, lines 19-14 (ORS Horii).

[31] Hearing, Vol 1, p. 354, lines 20-21 (JDA Chilton).

[32] Act 62. Section 58 41 30 (J)

[33] ORS Horii Surrebuttal, p. 5, lines 4-6.

to do a quick assessment and identify clear issues with some of the Companies' assumptions, future proceedings would benefit from a more expanded period of time allowed for testimony and rebuttal testimonies."[34] Power Advisory concurs with Mr. Horii's comments regarding the schedule.

In his Surrebuttal Testimony, Mr. Burgess recommends that Duke provide additional transparency regarding the following assumptions: (1) Detailed descriptions of must-run and cycling restrictions and the rationale for including these; (2) Hourly data on when must-run units are operating; (3) Hourly data on pumped hydro dispatch in the base case and change case; and (4) Hourly data on the timing of individual unit starts.[35] Given the significant proportion of hours with negative avoided costs such information would enhance the transparency of the Companies' avoided cost filing.

2.5 Avoided Energy Cost Estimates

The Companies use the peaker methodology to estimate avoided costs, which is a widely accepted industry standard approach to quantifying avoided costs.[36,37] As Mr. Snider notes in his Direct Testimony "[t]his approach assumes…the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal…energy costs that a utility avoids by purchasing power from a QF."[38] The Companies used a production cost simulation model (PROSYM) to estimate the hourly avoided energy costs of a fixed block of 100 MW that was assumed to be available throughout the year. The model is specified to reflect the Companies' generation resources including capacity ratings, outage rates, physical constraints (e.g., start times) and variable operating costs (i.e., fuel, environmental costs and variable operations and maintenance expenses). Hourly customer demand is also reflected, with the model dispatching generating units to meet hourly customer load at least cost. The Companies' noted that the "avoided energy and capacity costs are calculated using largely the same data inputs and assumptions presented in DEC's and DEP's 2019 IRPs."[39]

[34] ORS Horii Direct, p. 5, lines 10-13.

[35] SBA Burgess Surrebuttal, p. 13, lines 16-20.

[36] Mr. Horii characterizes the methodology as a Differential Revenue Requirement (DRR) methodology (ORS Horii Direct, p. 7.). Mr. Snider indicated that the DRR methodology is just a variant of the peaker methodology (Hearing Vol 1, p. 117, lines 10-11.).

[37] Hearing Vol 1, p. 45, lines 22-23 (Duke Snider).

[38] Duke Snider Direct, p. 10.

[39] Duke Snider Rebuttal, p. 9-10, lines 20-1.

To project avoided energy costs the model is run for both a "Base Case" and a "Change Case", which reflects the addition of a 100 MW generator available in all hours. The difference in the hourly energy cost between the Base Case and the Change Case is the hourly avoided energy cost. The Companies then aggregated these hourly avoided energy cost values into nine energy price periods in each year from 2020 to 2029, with these annual values levelized to produce 10-year levelized avoided energy cost estimates, which are adjusted for losses recognizing the assumed interconnection voltage of the QF on the Companies' system, incremental working capital requirements and applicable excise taxes. The nine energy pricing periods are summer premium-peak, on-peak, and off-peak; winter premium-peak, on-peak (AM and PM), and off-peak; and shoulder-season on-peak and off-peak.

Mr. Burgess offers a number of criticisms of the Companies' avoided energy cost estimates, a number of which Power Advisory believes warrant consideration and further discussion.[40] First of all, a significant portion of the hourly avoided energy costs are negative, particularly during periods when solar projects are likely to be operating. Second, the pricing periods that they have employed appear to inappropriately reduce the avoided energy cost rates during hours when solar resources are available. Each of these issues is discussed in turn.

2.5.1 Negative Avoided Energy Costs

In response to the SBA First Set of Interrogatories (2.b.) as well as other similar data requests, the Companies provided detailed summary spreadsheets of the hourly avoided cost modeling results of the difference between the Base and Change Case for both DEC and DEP. A review of these spreadsheets indicates that during a significant proportion of hours the estimated hourly marginal cost values are negative. In his Direct Testimony, Mr. Burgess indicates that for DEC 16% of the avoided cost hours calculated for 2019 through 2029 were negative and 10% for DEP.[41] Importantly for solar resources, Mr. Burgess notes that during the "summer peak periods, when both demand is high and solar resources are most available, the number of hours with negative avoided costs is as high as 20% or more for both DEC and DEP (See Figure 2).[42] Mr. Burgess

[40] In his Direct Testimony, Mr. Horii when asked if he recommended any changes to the Companies' avoided energy cost calculations or resulting rates stated: "No. Based on my review, the avoided energy costs reflected by the Companies in the Standard Offer tariffs are a reasonable result of the Companies' calculations." (ORS Horii Direct, p.10, lines 9-10). In his Surrebuttal Testimony, Mr. Horii disagrees with one element of Duke's modeling (major maintenance costs), but acknowledges the impact of this is negligible (p.4-6).

[41] SBA Burgess Direct, p. 22.

[42] Ibid.

estimates that the presence of these negative values results in a 30% reduction in total avoided costs (and corresponding QF revenues) for DEC and a 28% reduction for DEP.[43]

Figure 2. Burgess Estimate of DEP Percent of Summer Weekday Hours when Avoided Costs are Negative[44]

In their Rebuttal Testimony, the Companies responded to Mr. Burgess' criticism and seek to explain the incidence of negative avoided costs.

> "Negative avoided costs occur for a variety of reasons when QF energy is added to the system. For example, the inclusion of no-cost QF energy can shift combustion turbine ("CT") starts from one hour to the next, thereby creating an instance where a start cost is avoided in one hour but the cost is then incurred in the next hour. The addition of no-cost QF energy creates conditions that can lead to negative avoided costs in some hours that are seen in both the model, as well as on the actual Duke system."[45]

> "any time a generating unit is added to a resource stack, particularly a generator that acts like a baseload resource (such as a 100 MW no-cost resource) the timing of unit commitment and dispatch of the entire resource stack can change. In a security constrained unit commitment and dispatch model, the no-cost resource will impact the dispatch of a variety of units which can lead to changes in operating parameters such as the timing of unit starts, pump hours at pumped hydro storage facilities, and the timing

[43] Ibid.

[44] SBA Burgess Direct, p. 25.

[45] Duke Snider Rebuttal, p. 20 lines 10-17.

of ramps of conventional generators. The shifting of unit starts and pump hours at the hydro storage facilities account for the majority of negative avoided cost hours."[46]

"Over this time period, 16% of all hours in DEC contained "negative" avoided cost hours, while 10% of all hours in DEP contained "negative" avoided cost hours. The Companies then looked at the number of hours where either conventional unit start costs or a pumped hydro pump costs were incurred in the change case and not in the base case. In DEC, unit start and pumped hydro pump changes correlated with negative avoided cost hours 88% of the time. In DEP, unit start and pumped hydro pump changes correlated with negative avoided cost hours 80% of the time."[47]

Clearly, these negative values significantly affect the avoided costs available to solar QFs. To the degree that these negative avoided cost values are reasonable reflections of system costs stemming from operating constraints, then Power Advisory asked the Companies if avoided costs could be increased by constraining down QF generation in some hours. The Companies responded:

"It would not be possible to execute this strategy as solar curtailment would not reduce the "negative costs" referred to in the prior response. For instance, in the case of a CT start that was presented in Duke Witness Snider's rebuttal testimony, the reason that a negative avoided cost hour was incurred was not because there was an additional start, but rather the start was shifted out in time."[48]

On the other hand in response to a question from Vice Chair Williams, the Companies' Vice President of the System Planning and Operations Department, Mr. Holeman agreed that there are times when the Companies elect to decommit a generating unit given levels of solar output and then have to shortly thereafter start a unit and that this need to start a unit (e.g., a CT) could be avoided by dispatching down solar generation.[49] Power Advisory also notes that the Companies laud the operating flexibility provided by the North Carolina Competitive Procurement of Renewable Energy (CPRE) and cite this as a significant benefit relative to the lack of flexibility associated with PURPA-QFs. Power Advisory believes that there are potential savings from such operating flexibility that could benefit customers and QFs and make it easier to operate the Companies system, which have not been adequately acknowledged.

---

[46] DEC/DEP Response to Power Advisory Second Set of Interrogatories, #2-1 (a).

[47] Ibid., #2-1 (b).

[48] Ibid., #2-2.

[49] Hearing Vol 1, p. 316-319 (Duke Holeman).

2.5.2 Coal Unit Retirements

In late September Duke announced that it was accelerating the retirement dates of several coal-fired units including two coal-fired Allen Steam Units (Units 4 & 5) with a rated capacity of about 526 MW, which are now scheduled to retire in 2024 and Cliffside Unit 5 (540 MW), which is now scheduled to retire in 2026.[50] Mr. Snider acknowledged that these retirements could advance DEC's need for additional capacity to 2025, but indicated that this would have a relatively modest impact on avoided capacity rates for DEC.[51] Furthermore, he argued that there would be a corresponding change in avoided energy costs from the introduction of a new more efficient natural gas unit.[52] Mr. Burgess took an alternative perspective and asserted

> "the fact that these coal units are online in the first place means that they push down the remaining portion of the generation supply curve. This in turn will affect which gas generation unit is backed down due to the addition of a QF (relative to a scenario where the coal unit was not online). Put differently, if the must-run coal units were not included, the marginal gas unit that is displaced would more likely be a higher-cost, less-efficient gas unit. In that case, the avoided cost may be higher than what is currently modeled."[53]

Power Advisory also notes that the high proportion of hours with negative avoided energy costs could also be contributing to the presence of these relatively inflexible coal units that are being retired and with their retirement, the proportion of these avoided energy costs will be reduced. Power Advisory was unable to establish what the likely impact on avoided energy costs of these coal unit retirements would be. However, we recommend that for future avoided cost filings the Commission direct utility companies to base their avoided cost analyses on best available information that reflects anticipated unit retirements.

2.5.3 DEP East and DEP West Integration

Mr. Burgess also expressed concern with respect to how the Companies avoided cost analysis established avoided costs for DEP given the presence of two separate balancing areas (BAAs).[54] The Companies clarified that "DEP-East and DEP-West BAAs operate as a single DEP NERC Balancing Authority, and are interconnected through firm transmission interconnects that allow integrated system dispatch of all fleet generating units in DEP-East and DEP-West to serve load

---

[50] Hearing Vol 1, p. 147, lines 11, 15, p. 148, lines 8, 12 (Duke Snider).

[51] Ibid., p. 151, line 19.

[52] Ibid., p. 151, lines 23-24.

[53] SBA Burgess Surrebuttal, p. 12, lines 17 -24.

[54] SBA Burgess Direct, p. 68 lines 6-11 and p.69 lines 1-8.

in both DEP-West and DEP-East."[55] Furthermore, in response to a Power Advisory Interrogatory the Companies noted that "the DEP Balancing Authority Areas ("BAAs"), namely DEP West and DEP East, are interconnected through firm transmission that allows energy to flow from East to West and vice versa. In the production cost model, because of this firm transmission interconnection, when 100 MW of no-cost generation is added to the model, both DEP BAAs interact to re-optimize generation from the base case. As both BAAs are interconnected, the production cost delta is applied across the total DEP system."[56]

Importantly, DEP system operators commit and dispatch resources in DEP East and DEP West collectively to meet the collective load of the two BAAs. They do not independently commit and dispatch resources in each of the two BAAs. Finally, the Companies noted that "During three (3) instances over the last five (5) years, none within the past three (3) years, the transfer of energy has been constrained between DEP East and DEP West for a total four hours…less than 0.01% during the last five (5) years."[57] At the Hearing, Mr. Burgess argued that in markets relatively few hours of congestion can result in very high energy prices.[58] Power Advisory notes that Mr. Burgess' argument applies to competitive electricity markets with locational marginal prices where competitive generators can capitalize on transmission congestion to realize higher prices and resulting revenues and doesn't apply to a regulated electric utility where systems costs are based on directly incurred marginal operating costs. Based on the limited number of hours when there is congestion and the costing constructs used in a regulated electricity system, Power Advisory believes that there is not an issue that needs to be remedied, recognizing that in this instance the Companies modeling reflects system conditions.

2.5.4 Selection of Avoided Cost Periods

As discussed, the Companies have proposed nine energy pricing periods for the avoided energy costs. In response to a Power Advisory data request regarding why it is appropriate to establish distinct pricing periods, the Companies noted that:

> "the time-of-use rate design proposed by the Companies is applicable to all QFs, not just solar generators, and reflects the value of energy during each rating period. The proposed design was developed in response to a North Carolina Utilities Commission ("NCUC") requirement to offer more granular rates that better aligned with the actual cost of generation during each period…The rate design considerations … address forecasted cost,

---

[55] Duke Snider Rebuttal, p. 27-28.

[56] DEC/DEP Response to Power Advisory Second Set of Interrogatories, #2-4.

[57] Ibid.

[58] SBA Burgess Hearing Vol, p. 346-347.

future changes in Company load characteristics, and administrative concerns to be certain the design could be efficiently implemented and provide appropriate price signals over the entirety of a levelized contract term."[59]

The Companies assert that "the avoided energy payment rate designs provide sufficient seasonal and hourly granularity and appropriate price signals and incentives for QFs to maximize output during times when energy has the most value to the Companies and their customers."[60] In his Direct Testimony, Mr. Burgess asserted that "the arbitrary selection of time periods undervalues the true daytime avoided cost, therefore biasing against daytime QF production such as solar power. A different selection of pricing periods would more accurately reflect avoided cost [sic] and could significantly affect solar compensation."[61] In response to this critical assessment of these periods by Mr. Burgess, Mr. Snider argues, "the energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operation to maximize their production during hours that are most beneficial to retail customers and therefore, the system as a whole."[62]

Power Advisory notes that the vast majority of QFs that are likely to avail themselves of these avoided costs are non-dispatchable solar projects and are not able to adjust their operation to follow the price signals sent. The construction of these periods is important and the establishment of broad periods that are composed of hours with significantly varying prices can adversely affect the economic efficiency of these periods as discussed further below. As basic principle, electricity rates should be designed to reflect costs, to promote efficiency in the use or production of electricity and equity across customers or suppliers. These periods and the associated avoided costs for DEC and DEP are shown in **Figure 3** below. The Companies suggest that this is just an interest of solar QFs and imply that because the design of these cost periods may only affect one resource that such a concern isn't valid. Power Advisory notes that the vast majority of the resources that are to avail themselves of these avoided cost rates are solar QFs and that any bias to these resources warrants further consideration.

Furthermore, when asked whether avoided energy cost rates that varied by hour would be more appropriate the Companies noted "an hourly design using forecast energy data would yield different rates in each hour, but would fail to reflect real-world dynamics that cause actual cost to substantially differ from the ten-year weather normal forecast used to calculate rates in this proceeding. For example, in any given hour the system load response to abnormal weather and generation plant availability may cause a shift in the relative value of a particular hour. So while

---

[59] DEC/DEP Response to Power Advisory Second Set of Interrogatories, #2-3.

[60] Duke Snider Direct, p. 29.

[61] SBA Burgess Direct, p. 39.

[62] Duke Snider Rebuttal, p. 39.

the nine energy price periods outlined in this filing provide reasonable price signals between the identified periods, going to a more granular hourly forecast would not necessarily produce a better price signal."[63]

Figure 3: DEC & DEP Proposed Avoided Cost Periods and Rates[64]

Energy Rates

Independent Energy Price Blocks	1.Summer Premium Peak (PM)		2.Summer On-Peak (PM)		3.Summer Off-Peak		4. Winter Premium Peak (AM)		5.Winter On-Peak (AM)		6.Winter On-Peak (PM)		7.Winter Off-Peak		8.Shoulder On-Peak		9.Shoulder Off-Peak	
Company	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP
10-Yr Rate (cents/KWH)	4.58	3.30	4.48	3.11	2.60	2.68	5.04	3.58	4.61	3.54	4.15	3.42	2.70	2.75	3.39	2.98	2.28	2.26

DEC Energy — Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	3.Off												2.On (PM)				1.Premium				2.On (PM)		3.Off	
Winter (Dec-Feb)	7.Off					5.On	4.Premium			5.On	7.Off							6.On (PM)					7.Off	
Shoulder (Remaining)	9.Off						8.On				9.Off						8.On							9.Off

DEP Energy — Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	3.Off													2.On (PM)			1.Premium				2.On	3.Off		
Winter (Dec-Feb)	7.Off				5.On (AM)		4.Premium			5.On (AM)		7.Off							6.On (PM)				7.Off	
Shoulder (Remaining)	9.Off					8.On					9.Off							8.On						9.Off

Power Advisory performed some independent analysis of the projected hourly avoided costs to assess the degree to which the avoided cost energy pricing periods appear to inappropriately bias the value of energy realized by solar QFs. Such bias can occur if price levels within a pricing period vary significantly and a specific technology (e.g., solar) has a disproportionate share of its output in a portion of the pricing period with a higher or lower value. Specifically, solar projects produce only during daylight hours. If avoided costs are generally forecast to be higher during daylight hours, but the pricing period is composed of both some lower value nighttime hours and some higher value daylight hours, then these pricing periods would undervalue the solar QF's output and not properly reflect the value of this output to customers. This analysis suggested that there was a modest underpayment for solar QFs under DEC's rates and overpayment under DEP's rates. We recommend that the Commission direct the Companies to provide appropriate analytical support for their avoided cost periods in subsequent filings.

2.6 Large QF Avoided Cost Summary

Duke's Position

For large (greater than 2 MW) non-standard offer QFs, Duke plans to use the same peaker methodology. However, the inputs to the modelling are only discussed theoretically as the Companies plans to use most-recent available values at the time of performing the modelling. For

[63] DEC and DEP Response to Power Advisory Second Set of Interrogatories, No. 4.

[64] Duke Snider Direct, p. 27 Figure 3.

example, fuel costs will be updated to reflect the then-prevailing value of avoided fuel and the actual production profile of the large QF will be modelled.

Intervenor Comments

SBA witness Burgess in his Direct testimony, critiqued Duke's proposal for the development of avoided cost rates for non-standard offer QFs larger than 2 MW.[65] The peaker methodology adds a hypothetical 100 MW of no-cost generation to the utilities' generation fleet as reflected in the base case. This method makes no distinction between resource types. On the other hand, the proposed non-standard QF approach will take the specific supply characteristics into account and will include solar generation profile for solar QFs. Mr. Burgess argues that the estimation of avoided cost rates should be kept consistent across all QF contracts. Burgess claimed the methodological changes in the non-standard offer calculation are not transparent.[66]

Power Advisory Opinion

Duke is proposing to calculate the avoided cost rate for the large QF at the time of request. As such there isn't an opportunity to review these avoided costs. However, calculating the rate at the time of the request, ensures that the avoided cost rate reflects current assumptions and avoids the risk of stale avoided costs, which can be more significant for a large QF. Furthermore, the avoided cost rate will reflect the specific operating profile of the large QF and result in a more reliable avoided cost rate.

2.7 Avoided Capacity Cost Estimates

2.7.1 Assessment of Avoided Capital Cost Methodology

DEC and DEP have used the peaker methodology to estimate the avoided capacity cost. As Mr. Snider notes in his Direct Testimony "This approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF."[67] Mr. Snider notes that the Companies have consistently used the peaker methodology to forecast avoided energy and capacity costs and that the methodology has widespread acceptance.

[65] SBA Burgess Direct Amended, p. 29-31.

[66] Ibid.

[67] Duke Snider Direct, p. 10.

As noted in Mr. Snider's Direct Testimony, the peaker methodology implicitly assumes that peakers or simple-cycle combustion turbines represent ideal form of generation addition to meet future capacity needs. DEC & DEP's most recent Integrated Resource Plans (IRP) indicate that the most immediate utility sponsored capacity additions will be combined cycle gas turbines (CCGTs) and CTs.[68] For the ten-year term of the Companies' avoided cost forecast, DEP's IRP proposes the development of a 1,341 MW CCGT in 2025 and an additional 1,341 MW CCGT in 2027, with 470 MW of CTs in 2028 and 1,880 MW in 2029. DEC's IRP specifies a 470 MW CT in 2026 and a 1,341 MW CCGT in 2028.

DEP's most immediate capacity need is addressed by two CCGTs, suggesting that these are a better fit, with the incremental capital cost of the CCGT offset by additional energy savings produced by the CCGT's lower heat rate. DEC's most immediate capacity need is addressed by a CT, with a larger CCGT added two years later. Given the Companies' proposed resource additions, Power Advisory believes that the peaker methodology is reasonable methodological basis for establishing the companies avoided costs. Mr. Burgess concurs and notes that "the general framework (i.e., the Peaker Methodology) is sound."[69]

Mr. Burgess offers several criticisms of the Companies avoided capital cost estimates including: (1) the assumed capital cost of a new peaker are understated by the assumed technology type, economies of scale, and associated fixed costs; and (2) the timing of assumed capacity value from a QF understates this value.

2.7.2 Capital Cost of a New Peaker

Mr. Burgess recommends that an aeroderivative peaker be used as the basis for DEP/DEC's avoided capacity cost estimate. He argues that such a peaker is more likely to be representative than the type of resource that Duke adds for its avoided capital cost analysis (i.e., a lower capital cost frame unit). This may be true, but it doesn't mean that an aeroderivative peaker is the appropriate avoided cost benchmark. Mr. Burgess suggests that such an aeroderivative peaker maybe preferred by DEP/DEC because of its greater operating flexibility including quick start and ramping capability, both of which are valuable given higher solar penetration rates in their service territories. We note that these services represent additional value offered by this technology, value that is attributable to their ability to provide the associated ancillary services. We believe that this value should be deducted from the cost of these units. These are services that a QF solar unit isn't likely to be contracted to provide. Therefore, it would not be appropriate to base the solar resources' capacity payment on the aeroderivative peaker's capital cost because it isn't providing

---

[68] DEP/DEC, "Integrated Resource Plan Update Report 2019," September 2019

[69] SBA Burgess Direct, p. 44.

the same service.[70] Alternatively, the Companies may elect to install such an aeroderivative peaker for this incremental value, which could in turn be recovered by a solar integration charge.

In his Rebuttal Testimony, Mr. Snider makes a related argument. "I do agree with Mr. Burgess that aero-derivative CTs could be a future way for the Companies to manage the intermittent output of must-take solar generators. In that event, however, the cost causer for the more expensive aero-derivative CT would be the solar providers themselves and thus, the incremental cost of constructing aero-derivative CTs versus F-class CTs should be paid by the solar providers and not paid for by customers to the solar providers."[71] In essence, Mr. Snider is arguing that the incremental cost of an aero-derivative CT versus a F-class CT would be a proxy for the SISC. Power Advisory agrees with the Companies.

In his Direct Testimony Mr. Snider notes "the Companies adjusted the EIA data to reflect the economies of scale associated with land, buildings, roads, security, gas interconnection and other infrastructure for a 4-unit CT site."[72] Mr. Burgess also critiques the Companies' capital cost estimate given that it reflects a $70/kW credit for economies of scale offered by a four-unit CT. The Companies responded that eight of their eleven sites with CTs have four or more CTs so its economies of scale adjustment is appropriate and reflects the ability to share infrastructure among multiple CTs, which reduces the CT's unit costs ($/kW).[73] Power Advisory agrees with the Companies.

Mr. Burgess also argues that the Companies should include the costs of transmission upgrades necessary to interconnect the CT to its transmission network.[74] Mr. Snider noted that "[s]ometimes a utility's construction of new generation facilities will require transmission upgrades, but not all new generation additions require such upgrades."[75] Power Advisory notes that avoiding transmission upgrades can be an important driver of the location of new utility resources and as a result believes that adding such a cost is likely to be speculative and inappropriate without additional evidence that such network upgrades are likely.

2.7.3 Capacity Value Timing

Mr. Burgess also asserts the Companies underestimated the capacity value in terms of timing. The Companies effectively acknowledged this with respect to DEC given the recently announced retirements of Allen Units 4 & 5 and Cliffside 5, which would advance DEC's need for additional

[70] Power Advisory acknowledges that Mr. Burgess does assert that solar projects can provide a number of the services that more traditional resources that provide reserves offer.

[71] Duke Snider Rebuttal, p. 44.

[72] Duke Snider Direct, p. 15, lines 2-5.

[73] Duke Snider Hearing, Volume 1, p. 241 lines 12-15.

[74] SBA Burgess Direct, p. 58-59.

[75] Duke Snider Rebuttal, p. 48 lines 8-10.

capacity to 2025. As discussed earlier, the Companies argue that there would be a more than offsetting reduction in avoided energy costs, which they suggest makes an adjustment of avoided capacity costs for DEC inappropriate or unnecessary. Power Advisory doesn't agree that this is necessarily the case given that inflexible higher cost coal units could reduce avoid energy costs when operating at minimum load to ensure their availability in other periods. Therefore, we recommend that DEC's avoided capacity cost be adjusted to reflect a one-year acceleration of the year in which capacity is required to 2025.

With respect to DEC, it assumes no capacity value prior to 2026, the first year of anticipated need and assumes no capacity value after 2029 for either Company. Mr. Burgess asserts that DEC QFs can provide capacity prior to 2026 and by so doing enable DEC to make additional sales of surplus capacity and therefore, this capacity value should be considered based on its market value. In his Rebuttal Testimony, Mr. Snider argues that:

> "From a legal perspective, utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA. FERC has long held that 'an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…[the purchase] obligation does not require a utility to pay for capacity that it does not need.'[76] FERC has also expressly stated that 'there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity.'"[77]

With respect to the second issue of no assumed capacity value after 2029, the analysis and valuation period is through 2029. While the Companies my realize additional value at the end of the contract term this is by no means certain. Mr. Snider argues that "at the time their current PPA expires whether or not to establish a new legally enforceable obligation ("LEO") and contractually commit to deliver their full output, including capacity, to the utility, whether to cease operations after their current contract expires, or whether to otherwise use their facility in any lawful manner they so desire, based on the current economic, regulatory, and market circumstances existing at the time their current PPA expires."[78] Power Advisory believes that reflecting capacity value after 2029 in the avoided capital cost estimates would violate the direction in Act 62 to "reduce the risk placed on the using and consuming public."

---

[76] City of Ketchikan, 94 FERC ¶ 61,293 (2001) ("Ketchikan") citing Order No. 69, FERC Stats. & Regs., Preambles 1977-1981, P30,128 at 30,865.

[77] Ibid.

[78] Duke Snider Rebuttal, p. 56.

2.7.4 Weighting of Peak Periods

Duke utilized an analysis performed by Astrapé Consulting that assessed the Loss of Load Expectation (LOLE) on a seasonal basis to set a seasonal weighting for avoided capacity. As stated in Witness Snider's direct testimony:

> "Seasonal allocation places capacity value into the appropriate season of the year that drives the Companies' reliability need for new capacity resource additions. For DEC and DEP, seasonal allocation is now heavily weighted to winter based on the impact of summer versus winter loss of load risk, which has been driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. As presented in detail in the Solar Capacity Value study conducted by Astrapé Consulting and described in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter.16 Thus, DEP's filed rates in this proceeding pay all of its annual capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and the remaining 10% in the summer period." [79]

As stated in Duke's evidence above, DEC and DEP are now primarily winter peaking for two main reasons: the growing penetration of solar capacity and volatility in winter peak demand. However, intervenors disagreed with Duke's position for several reasons.

ORS Witness Horii's concern is that Duke's analysis undervalues solar capacity because Duke is effectively assuming future solar capacity that is not yet contracted and is impacting the value of current solar capacity. In essence, Mr. Horii suggests the avoided costs put forth are calculated reasonably, but the assumption of how much solar capacity on the system is incorrect and as a result the avoided capacity value of solar resources is under-stated. As outlined in Mr. Horii's Direct Testimony:

> "DEC correctly allocates the capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period. However, DEC uses LOLEs based on 3,500 megawatts ("MW") of solar penetration on the DEC system. 3,500 MW of solar penetration is "Tranche 4" in the analysis nomenclature which is the highest level of solar penetration evaluated, and reflects solar penetration levels far in exceedance of current levels. DEC's allocations of avoided capacity costs to season and time of day, therefore reflect capacity needs too far into the future, rather than reflect what system capacity needs would be in 2020 when there are only approximately 840 MW (Company witness Snider direct testimony, page 35) of solar on the system.

---

[79] Duke, Snider Direct, p. 19.

> This is problematic because the timing of the need for capacity when there are 840 MW of solar on the DEC system is not the same as the timing of the need for capacity when there are 3,500 MW of solar on the system. With the higher level of solar generation, the need for system capacity shifts away from hours when the already installed solar is generating."[80]

Duke disputes this characterization on the basis that the solar capacity projections used in their analysis can be reasonably expected to occur as they are largely mandated by North Carolina law, specifically NC HB 589.

> "North Carolina Session Law 2017-192, House Bill 589 ("N.C. HB 589") established the Competitive Procurement of Renewable Energy ("CPRE") Program competitive solicitation process, which calls for the addition of 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period. The total CPRE target of 2,660 MW via annual competitive solicitations will vary based on the amount of "Transition" MW at the end of the 45-month period, which N.C. HB 589 expected to total 3,500 MW. If the aggregate capacity of the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount. N.C. HB 589 also allows for up to 600 MW of renewable energy procurement programs for large customers such as military installations and universities, as well as a community solar program.
>
> At the time that the Solar Capacity Value study was being conducted, the Companies' projection of total solar mandated by N.C. HB 589 and solar included in SC Act 236 corresponded to the "Tranche 4" level of solar in the study, which reflected 3,500 MW of cumulative solar for DEC and 3,585 MW for DEP. While the exact timing and amounts of transition and incremental solar additions may change over time, the Companies believe that it is reasonable to assume the cumulative mandated levels of solar under Tranche 4 for purposes of calculating the standard offer avoided cost rates."[81]

Mr. Snider suggests that the Tranche 4 level of solar capacity is the correct one to avoid double counting and over-payment.[82] Mr. Horii updated ORS' view in his Surrebuttal Testimony, but maintained the key point that avoided capacity costs should be set based on current conditions. He also suggests there is no overpayment risk by basing avoided costs on current conditions.

> "The total "Tranche 4" MW of renewable generation contemplated in the Competitive Procurement of Renewable Energy ("CPRE") Program is mandated by North Carolina law (HB589) to be integrated by a certain date in the future. However, avoided costs should be calculated based on current conditions. Specifically, Act 62 states "[e]ach electrical

[80] ORS Horii Direct, p. 14.

[81] Duke Snider Rebuttal, pp. 59-60.

[82] Duke Snider Rebuttal, p. 63.

> utility or incurred by the electrical utility…". "Tranche 4" represents an amount of future solar that has not yet committed to a contract price for power. As such, there is no overpayment risk because future solar will be evaluated based on avoided cost rates that exist at that time in the future. To be sure, if the future solar were paid based on higher avoided costs from the past, there would be an overpayment risk, but that risk would have nothing to do with the Qualifying Facilities' ("QF") solar.
>
> If avoided cost rates are calculated correctly, as I propose, they would reflect the cost conditions that exist at the time any contracts are signed. Overpayment would only occur if one group of solar QFs were paid based on a cost higher than actual avoided cost levels."[83]

Based on an updated understanding of current conditions, Mr. Horii suggested in his Surrebuttal Testimony that Tranche 1 solar capacity assumptions are the most appropriate.

> "In my direct testimony I recommended seasonal allocation factors based on the Loss of Load Expectation ("LOLE") from the Companies' "Existing Plus Transition" solar penetration case. With the signed CPRE contracts, solar penetration is comparable to the "Tranche 1" case, and I now recommend seasonal allocation factors based on the "Tranche 1" case. Using the same method described in my direct testimony, I calculated updated allocation factors shown below in Table 3 compared to DEC's proposed values and those I recommended in my direct testimony."
>
> Table 3 now shows Horii's view that DEC's capacity values should be weighted 30% to summer and 70% to winter.[84] DEP's capacity values, based on Horii's analysis, are weighted 99% winter and 1% summer, and did not change in his Surrebuttal Evidence.[85]

SBA Witness Burgess also disagreed with Duke's weighting on the basis of a number of concerns with Duke's modeling approach and assumptions.[86] In order to address these concerns, Mr. Burgess proposed that the seasonal capacity allocation be developed based on historical load patterns. "I recommend that the seasonal allocation that reflects this historical pattern as shown in the table above. I believe this is a simple and transparent approach and is an accurate representation of when Duke's historical peak loads have occurred. Additionally, this avoids any potential influence from opaque modeling approaches and associated inputs." [87]

---

[83] ORS Horii Surrebuttal, pp. 7-8.

[84] ORS Horii Surrebuttal p. 10.

[85] ORS Horii Surrebuttal p. 11 and ORS Horii Direct, p. 18 for the 1% capacity value.

[86] SBA Burgess Direct, pp. 47-48.

[87] SBA Burgess Direct, p. 53.

Duke disputed this approach, primarily on the basis that it only considered load and did not consider the impact of non-dispatchable solar generation.

> "SBA Witness Burgess and SACE/CCL Witness Wilson point out that DEC and DEP experience significant summer demands. However, as previously discussed, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any – solar is available at the time of peak. Thus, in the summer peak, loads net of solar output are reduced relative to winter peak loads net of solar. With the significant penetration of solar resources in recent years, the Companies no longer serve load, but rather serve load net of must-take solar output. It is the load net of solar that has an impact on summer versus winter reserves and LOLE values, and represents the actual net load that the remainder of the Companies' resources must satisfy. SBA Witness Burgess appears to completely ignore this fact in his analysis."

Mr. Burgess acknowledged Duke's concern in his Surrebuttal testimony, and developed revised summer/winter weightings based on the load shape approach he advocates as an alternative to the Duke approach. Mr. Burgess also addressed Duke's concern that his analysis relied on an excessive number of hours, and restricted his approach to the top 0.1% of peak net load hours, as compared to the top 10% of gross load hours in his original approach.[88] Based on this revised approach, Mr. Burgess estimates DEP as 96% winter and 4% summer, and DEC as 42% winter and 58% summer.

SACE/CCL Witness Wilson also identified concerns with Duke's analysis that the capacity need in the winter was over-stated relative to the summer need. In particular, Mr. Wilson suggested that Duke's resource adequacy studies exaggerated the increase in load due to low winter temperatures, as well as the peak winter demand response and operating reserve assumptions.[89]

With respect to the concern that the risk of winter peak loads is over-stated, Mr. Wilson provides evidence that the linear regression approach used by Duke is overly simplistic and exaggerates the load response to extreme temperatures.[90] Mr. Wilson outlines his view that the relationship between low temperatures and increased load weakens at very low temperatures largely because the demand induced by the low temperatures has already largely occurred.[91]

> "Through discovery, the Companies provided data showing the scenarios (weather year, day, hour, load forecast error assumption), that led to lost load in the 2016 RA Studies. For DEP, using all years, the RA Study has 86% of the expected load loss hours in winter; if only weather data 1997 and later is used, 75% of the load loss hours are in summer and only

---

88 SBA, Burgess Surrebuttal, p. 21.

89 SACE/CCL Wilson Direct, p. 28.

90 SACE/CCL Wilson Direct, pp. 32 Figure JFW-1 for example illustrates that at extremely low temperatures Duke's approach potentially over-estimates load by over 1,000 MW.

91 SACE/CCL Wilson Direct, pp. 31, paragraph 20.

> 25% are in winter. For DEC, 69% of the expected load loss hours are in winter in the RA Study; but if only weather since 1997 is modeled, 92% of the load loss hours are in summer, 8% are in winter. This data shows that in the RA Studies, the vast majority of the hours with load loss result from scenarios based on those instances of extreme cold from the 1980s and 1990s, and the overstated loads associated with them due to the flawed regressions. While including more rather than less historical weather data is preferred, excluding the 1982-1996 data quantifies how the flawed regressions have skewed the results and overstated winter resource adequacy risk. The data strongly suggest that if the regressions were corrected, the resource adequacy risk would still be weighted toward summer on both systems."[92]

Duke disagreed with Mr. Wilson's assessment, and noted that this issue has been examined and Duke has largely addressed concerns with the impact of extreme weather.

> "Load uncertainty due to extreme temperatures is a significant driver of LOLE and can be challenging to capture since there are few instances in recent history to correlate load with extreme temperatures. Based on results of some additional sensitivities requested by the NC Public Staff, the NC Public Staff was satisfied that the approach taken to capture the correlation of load and extreme weather was reasonable."[93]

In Surrebuttal Testimony, Mr. Wilson stated that the response of demand to extreme weather events was not covered in the Joint Report issued. Specifically, Mr. Wilson noted:

> "This [why NC Public Staff was satisfied] is not known; while the NC Public Staff's section of the Joint Report discusses other issues in some detail, with regard to this issue, NC Public Staff simply stated (p. 2), "After meeting with the Company, the Public Staff was satisfied that this approach was reasonable." NC Public Staff did not state why it dropped this issue. The Companies' section of the Joint Report was also silent on this issue.
>
> The December 2017 Presentation, however, addressed this issue over twelve slides, at pp. 9-20. In particular, this presentation included a sensitivity analysis that suggested this issue had only a modest impact on reserve margins (0.3%; p. 14). Perhaps NC Public Staff was swayed by this sensitivity analysis."[94]

Power Advisory Assessment

Power Advisory agrees with Mr. Horii that avoided costs should be calculated based on current solar levels, rather than expected future solar levels even where these are based on a legislated policy commitment. In effect, the avoided capacity cost of solar added to the system today should

[92] SACE/CCL, Wilson Direct, pp. 35-36

[93] Duke, Snider Rebuttal, pp. 75-76.

[94] SACE/CCL, Wilson Surrebuttal, p. 6.

be based on the amount of solar on the system today. Future additions would be based on the avoided cost at the time they are added, which would reflect the then current levels of avoided costs. This ensures there is no risk of overpayment. As such, Power Advisory believes that the capacity weightings proposed by Mr. Horii in his Surrebuttal Testimony are reasonable and that the Companies should be directed to update their avoided capacity cost rates to reflect these weightings.

Power Advisory notes that Mr. Wilson's evidence is compelling that Duke's approach to modeling the impact of extreme temperatures is problematic. However, Mr. Wilson's evidence does not suggest specific changes to be made to the summer vs. winter capacity ratings without further analysis. Power Advisory also notes that while the impact on required reserve margins of 0.3% noted by Mr. Wilson is not a material concern, this does not mean that the impact on the weighting of capacity value between summer and winter seasons is also immaterial.

Power Advisory believes the LOLE studies used by Duke are an appropriate methodology to assess the seasonal contribution of capacity. As such, the seasonal estimates put forth by Mr. Burgess using a simpler methodology should not be adopted, but represent a reasonable check on the LOLE modeling.

3. SOLAR INTEGRATION CHARGES

3.1 Companies' Proposal

The Companies propose a Solar Integration Services Charge (SISC) based on an estimate of the average ancillary service cost of integrating variable solar generation. The Companies engaged Astrapé Consulting (Astrapé') to conduct a Solar Ancillary Service Study to analyze and quantify the ancillary service impact of integrating existing and future solar generation on both the DEC and DEP systems. Astrapé employed its proprietary Strategic Energy & Risk Valuation Model (SERVM) to conduct this Solar Ancillary Service Study. SERVM is used to estimate the required increase in regulating reserves and contingency reserves on the DEP and DEC systems to comply with mandatory North American Electric Reliability Corporation (NERC) resource and demand balancing (BAL) reliability standards.

The Companies' witness Nick Wintermantel explains that "The NERC BAL standards are minimum reliability requirements, so additional online reserves (frequently referred to as load following reserves) must also be carried due to net load uncertainty and intra hour volatility as well as the need to respond to unplanned generator outages. The more uncertain and volatile net load becomes, the more load following reserves are required to maintain the balance between resources and demand and thus, compliance with NERC BAL Reliability Standards in real-time."[95]

Astrapé developed a special metric to estimate the required increase in regulating reserves and contingency reserves from increases in solar energy on the DEP and DEC systems. Specifically, Astrapé created a Loss of Load Expectation (LOLE) based on its estimate of the number of loss of load events due to system flexibility constraints, calculated in events per year ($LOLE_{FLEX}$). Wintermantel characterizes this reliability metric in terms of "there was enough capacity installed on the system but not enough flexibility to meet the net load ramps caused by solar generation, or startup times prevented a unit coming online fast enough to meet the unanticipated ramps."[96]

Astrapé used SERVM to estimate the increase in regulating reserves and contingency reserves costs for an "Existing plus Transition" scenario which reflects 2020 solar installations of 840 MW and 2,950 MW in DEC and DEP and "represents the solar penetration the Companies expect to be installed on the DEC and DEP systems by 2020."[97]

Mr. Wintermantel explains: "SERVM commits resources to meet expected hourly net load and then randomly selects (or draws) from the intra hour historical datasets for load and solar separately

[95] Duke Wintermantel Direct, p. 6.

[96] Duke Wintermantel Direct, p. 15.

[97] Duke Snider Direct, p. 36.

based on similar conditions. In other words, to simulate a peak load hour, SERVM randomly selects five-minute volatility data from the set of peak load hours in the historical intra hour load dataset. The selected five-minute volatility data for that hour is then applied to a perfectly smooth net load profile causing five-minute deviations. The conventional fleet is then forced to serve the net load with volatility. [98] In essence, these five-minute deviations must be balanced by the available generation fleet or a violation is recorded.

Based on this analysis, the Companies are proposing Solar Integration Service Charges of $1.10/MWh for DEC and $2.39/MWh for DEP.

3.2 Solar Integration Services Charge Settlement

The Companies' proposed SISC and the methodology employed to develop it were the subject of considerable dispute among the parties. Prior to the commencement of the hearings, various parties submitted a partial settlement agreement covering the SISC.[99]

The North Carolina Utilities Commission (NCUC) issued a supplemental notice of decision on October 17, 2019, in the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018. The decision addressed issues relating to DEC/DEP's proposed SISC. The issues addressed in the decision are some of the same as those being considered by the Commission in this proceeding. The highlights from the NCUC's directive are described below.

- All parties in the proceeding agree that DEC and DEP incur additional costs to integrate "Existing plus Transition" level solar QF facilities. It was also agreed that the quantification of near-term projected capacity represented by "Existing plus transitional" for DEC and DEP as 840 MW and 2950 MW is accepted as reasonable.
- Astrapé study's determinations that an additional 26 MW of load following reserves are required to integrate 840 MW of solar QFs in DEC, at an average cost of $1.10/MWh, and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar QFs in DEP, at an average cost of $2.39/MWh, are reasonable for use in this proceeding.
- It is also accepted that DEC and DEP incur additional ancillary services costs and will account for these when calculating costs and benefits resulting from purchases of energy and capacity from solar QFs.
- Duke will also be required to calculate non-SISC rates available to controlled solar generators.

[98] Duke Snider Direct, p. 12.

[99] The parties included DEC/DEP, SBA, JDA and SACE/CCL.

With the issuance of this supplemental decision that pertained to a study that was also submitted in this proceeding the parties entered into settlement negotiations. The resulting settlement agreement is summarized below.

1. DEC and DEP's quantification of near-term project capacity reflected by "Existing plus Transition" solar QF's to be installed, namely 840 MW and 2,950 MW, is reasonable.
2. For the purposes of this proceeding, the SISC of $1.10/MWh and $2.39/MWh for DEC and DEP are reasonable. This applies to small solar power producers that enter into PPAs or any Legally Enforceable Obligation before the effective date of avoided cost calculations filed in the next DEC / DEP avoided cost proceeding before the Commission. These charges will not be subject to any adjustment during the term of the PPA.
3. The SISC cannot be imposed on a "controlled solar generator". This refers to any solar QF that is capable and agrees to operate in a manner that materially reduces or eliminates the need for additional ancillary services incurred by Duke. This includes but is not limited to solar with battery storage. Duke is required to submit to the Commission, the guidelines to establish controlled solar generator by November 18, 2019.
4. The Astrapé study used to calculate the SISC warrants further review. Duke will submit all inputs and methodology of the Astrapé study for an independent technical review. The results of the review are to be filed in the next avoided cost filing by Duke for Commission review and interested parties to comment on.
5. Duke will submit revised Standard Offer and Large QF PPAs reflecting the stipulations of this settlement within 15 days of the Commission's final order approving the SISC.

Power Advisory accepts this settlement agreement as a reasonable accommodation among the parties regarding the contentious issues surrounding variable resource integration charges.

4. FORM CONTRACT POWER PURCHASE AGREEMENTS, COMMITMENT TO SELL FORMS, AND OTHER RELATED TERMS AND CONDITIONS

4.1 Background on Commercially Reasonable Terms and Conditions

Act 62 specifies that the Commission should treat QFs on a fair and equal basis with electric utility-owned resources while protecting ratepayer interests. The relevant sections of the Act as it relates to this chapter of the report include the following (emphasis added):

- "Within such proceeding the commission shall approve one or more standard form power purchase agreements for use for qualifying small power production facilities not eligible for the standard offer. Such power purchase agreements shall contain provisions, including, but not limited to, **provisions for force majeure, indemnification, choice of venue, and confidentiality provisions** and other such terms, but shall not be determinative of price or length of the power purchase agreement. The commission may approve multiple form power purchase agreements to accommodate various generation technologies and other project specific characteristics."[100]
- "A small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility. The commission shall approve a standard notice of commitment to sell form to be used for this purpose that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement. **In no event**, however, **shall the small power producer**, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, **be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility**."[101]
- "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."[102]

[100] Act 62. Section 58 41 10. (A)

[101] Act 62. Section 58 41 10. (D)

[102] Act 62. Section 58-41-20. (A)

- "In implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources by ensuring that power purchase agreements, including terms and conditions, are **commercially reasonable** and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."[103]
- "In establishing standard offer and form contract power purchase agreements, the commission shall consider whether such power purchase agreements should prohibit any of the following: (a) **termination of the power purchase agreement**, **collection of damages from small power producers**, or commencement of the term of a power purchase agreement prior to commercial operation, if delays in achieving commercial operation of the small power producer's facility are due to the electrical utility's interconnection delays"[104]
- "The commission is expressly directed to consider the potential benefits of terms with a longer duration [than 10 years] **to promote the state's policy of encouraging renewable energy**."[105]

In this chapter, we examine terms and conditions of the Standard Offer PPA, the Large QF PPA and the Notice of Commitment to Sell Form, and consider their commercial reasonableness.

As specified by Act 62 a critical standard for assessing the reasonableness of the terms and conditions is the degree to which they are commercially reasonable. In the most basic sense commercially reasonable means terms and conditions that are consistent with concepts of good faith and fair dealing. For a PPA this requires a balancing of various principles and concepts including: (1) the terms and conditions should conform to industry norms and what is typical, with good comparables being other PURPA PPAs; (2) result in an appropriate alignment of risk, with risks best managed by those who have control over them; (3) the terms and conditions should not unduly impair the ability of the QF to secure financing. For example, if there is an unreasonable risk of termination of the PPA that cannot be adequately mitigated by the QF, or financial penalties that would imperil the ability to cover debt service, without a reasonable opportunity to remedy, or other significant risks related to the cash flows, the project would be in jeopardy of not securing financing; and (4) the terms and conditions should be reasonable from the perspective of

[103] Act 62. Section 58-41-20. (B) (2)

[104] Act 62. Section 58-41-20. (E) (3) (a)

[105] Act 62. Section 58-41-20. (F) (2)

ratepayers and reflect the objective in the Act to reduce the risk placed on the using and consuming public. [106]

In our comments below, we have attempted to strike a reasonable balance between treating QFs on a fair and reasonable basis and protecting ratepayer interests, while striving to reduce the risk placed on the using and consuming public.

4.1.1 Implications of 10-year PPA Contract Length in South Carolina

Introduction

As discussed, Act 62 represents a delicate balancing of the interests of the "consuming public" and the interests of QFs, while "striving to reduce the risk placed on the using and consuming public." However, as various parties pointed out the Act was passed unanimously in the South Carolina House and Senate. Given the effort devoted to drafting this legislation it would appear that there was an expectation by legislators that the Act would engender a response beyond the filings by various electric utilities. Nonetheless, Act 62 by no means establishes ensuring QF project development as a threshold. However, we expect that the Commission would be interested in understanding the implications of the proposed avoided costs on the resulting opportunities for QF development in South Carolina, recognizing that the Act provides:

> "Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost."[107]

[106] Reflecting the balancing of these principles and the appropriate risk allocation, the QF is ultimately responsible for project construction and operation and the terms and conditions should provide proper incentives to ensure that these responsibilities are discharged in a manner the project provides the value that the utility has contracted for."the Scheduled Commercial Operation Date shall be no more than three years from the date the Effective Date."
PacificPower "Oregon Standard Power Purchase Agreement (New QF)", approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3.
https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_New_Firm_QF_And_Intermittent_Resource_with_MAG.pdf

[107] Section 58-41-10. (F)(1)

Discussion

Contract length was an important issue in this proceeding, with a number of intervenors arguing that contract lengths longer than 10-years were essential if QFs were to secure regularly-available market-rate financing, under the term employed by Johnson Development Associates, Inc. Witness Ms. Chilton. In discovery, Duke's questions centered on the basis for an obligation for QFs to obtain regularly-available market-rate financing and a standard of commercially reasonable access to capital in these dockets. In response, JDA highlighted the FERC precedent of *Windham Solar LLC and Allco Finance Limited*, 157 F.E.R.C. P61,134, ¶ 8, which states that PURPA contract term lengths "should be long enough to allow QFs reasonable opportunities to attract capital from potential investors" as well as Act 62. As JDA notes, the Act specifically allows the Commission to approve contracts beyond 10-years and asks it to consider such longer durations.[108]

At the heart of whether the 10-year contract term is sufficient or not to enable financing under reasonable terms is the contract price. As contract length shortens, the required PPA price to secure conventional financing increases owing to the riskiness of the cash flows in the post-PPA period. This relationship is illustrated in

Figure **4**. The figure contains PPA pricing for 30-year, 20-year and 10-year PPAs. In late 2017, through competitive bid, Georgia Power contracted for 510 MWs of solar in Georgia with an average price of $36/MWh for 30-year contracts.[109] Eighteen months later, in 2019, Duke contracted for 550 MWs of solar projects in North Carolina (CPRE Tranche 1) for an average price of $38/MWh for 20-year contracts.[110] Owing to the increased riskiness of the cash flows in the post-PPA term, the $/MWh price for a 10-year PURPA contract in South Carolina would need to exceed the $38/MWh figure. The problem is that the currently proposed avoided cost rates for the Companies are expected to be about $30/MWh, well below these figures.[111] Thus, without longer contract length, the solar industry would not be able to finance PURPA projects in South Carolina because they would not be economical. While the bar on the right shows a required PPA price to secure financing, Power Advisory has not calculated that price so the top part of the bar is illustrative only.

---

[108] S.C. Code Ann § 58-41-20(F)(2)

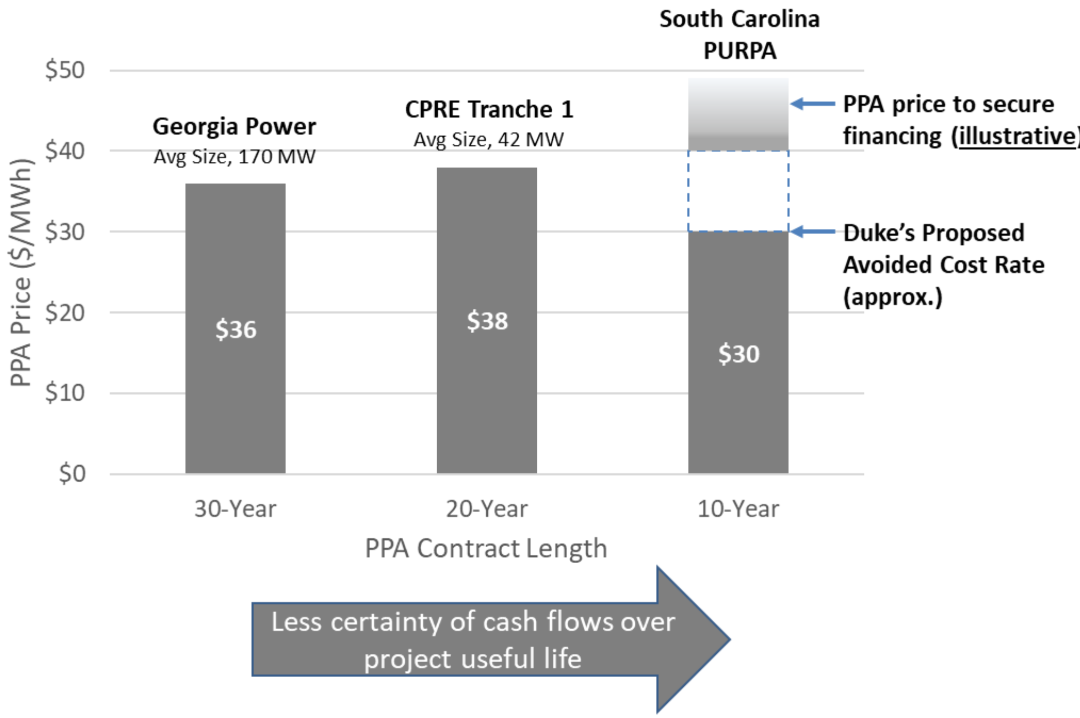
"Act No. 62 of 2019 states that the "[C]omission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, …"5 and "The [C]omission is expressly directed to consider the potential benefits of terms with a longer duration to promote the state's policy of encouraging renewable energy."

[109] Georgia Power, "Georgia Power renewable growth to continue throughout 2018: 970 MW of solar capacity online today, 510 MW of new solar contracts recently awarded" March 13, 2018 https://southerncompany.mediaroom.com/2018-03-13-Georgia-Power-renewable-growth-to-continue-throughout-2018

[110] Hearing Vol 2, p. 181 lines 9-13 (Duke Brown).

[111] Ibid.

Figure 4. PPA Price ($/MWh) vs. Contract Length (Years)[112]



It's also important to note two things that could drive required PPA prices in South Carolina higher than these other benchmarks:

- The Investment Tax Credit (ITC) declines from 30% in 2019 to 26% in 2020, to 22% in 2021 to 10% in 2022, thus eroding solar economics over time (and drives required PPA prices higher).
- The comparable PPA rates for 30 year and 20 year have average project sizes of 170 MWs and 42 MWs, respectively. These sizes are much higher than the average South Carolina PURPA projects. Thus, project economics would be worse.

Two other investor concerns related to the 10-year contract length include the following:[113]

- It is hard to forecast the avoided cost of a given utility to understand what the pricing will be 10 years from now.

---

112 Power Advisory.

113 Norton Rose Fulbright, Project Finance NewsWire, August 2019, p.2, column 2, paragraph 4; accessible at: https://www.projectfinance.law/newswire-archive/august-2019/

- There is regulatory risk in terms of whether there will still be a utility purchase obligation 10 years from now.

This is in contrast to an organized power market such as PJM, ISO-NE or ERCOT where there is a liquid market for electricity in the post-PPA term and far more confidence in the price forecasts. In addition, a hedge product can be used to put a floor under the electricity prices. As a result, shorter term PPAs are possible in these organized markets. By contrast, the risks in South Carolina in the post-PPA period are much harder to mitigate.

4.1.2 Risk Mitigation

One opportunity that would mitigate the risk to the investors in the post-PPA period would be to have some sort of upper and lower price bounds. This concept was raised by Mr. Levitas in his hearing testimony.[114] However, it would defeat the purpose of ensuring up to date rates for the ratepayers as the rates and guaranteed price range might not overlap.

Intervenor Proposals for Terms and Conditions for Longer PPA Lengths

It is important to note that the Intervenors were planning to propose terms and conditions for longer PPA lengths, however, Power Advisory did not receive these prior to submission of this report.

4.1.3 Comparison with PURPA contract lengths in other states

Power Advisory reviewed contract lengths in some of the most prominent PURPA states, where the market for PURPA projects has been the greatest over the past 10 years in megawatts (Figure 5). The average contract length of 15 states as shown in the figure is currently 14.1 years, down from 15.5 years when taking into account regulatory actions over the past few years. The current contract lengths ranged from 2 to 25 years, with a median of 15 years.

[114] Hearing Vol 1, p. 347 (SBA Levitas).

Figure 5. PURPA Contract Length by State Sorted Longest to Shortest [115]

State	Current Term (Years)	Date Effective	Increase/Decrease	Previous Term (Years)
Montana	25	Apr-19	Retained same	25
Vermont	25		Same	25
Oregon	20	Mar-16	Retained same	20
Wyoming	20	Jun-16	Retained same	20
New Mexico	20		Same	20
Michigan	20		Same	20
Utah	15	Jan-16	Decrease	20
Washington	12	Jun-19	Increase	5
Connecticut	12		Same	12
North Carolina	10	Oct-17	Decrease	15
South Carolina	10	May-19	Retained same	10
California	10		Same	10
Mississippi	5		Same	5
Georgia	5		Same	5
Idaho	2	Aug-15	Decrease	20
Average	**14.1**			**15.5**

The most significant change in contract length over the past few years occurred in Idaho, the third largest PURPA market over the last 10 years in megawatt additions, according to data from EIA.[116] In August 2015, at the request of the utility, the Idaho Public Service Commission reduced the PURPA contract length from 20 years to 2 years.[117] That made it the shortest PURPA PPA contract

---

[115] Power Advisory, based on various regulatory filings, Standard Offer PPAs and associated documents

[116] Data are from the US Energy Information Administration (EIA), EIA-860 database https://www.eia.gov/electricity/data/eia860/

[117] Idaho Public Utilities Commission, "Idaho commission reduces contract length for some PURPA projects to two years" Case No. IPC-E-15-01, AVU-E-15-01, PAC-E-15-0, August 19, 2015. https://puc.idaho.gov/press/150820_PURPAfinal_files.pdf

length in the US and remains that way to this day. Although the QF was eligible for continual renewal of its contract every two years at then-current avoided costs, this effectively turned the project into a merchant plant, which had relatively little long-term revenue certainty. Since this ruling, no new QF projects of greater than 1 MW have become operational in Idaho according to data from EIA. In the wake of this change, several other utilities have requested their regulator reduce contract lengths to shorter durations. Some of the results of those requests are as follows:

- In Utah, the utility requested a reduction from 20 to 2 years, but the Public Service Commission decided to reduce it more moderately, from 20 to 15 years.[118]
- In Wyoming, several utilities asked its regulator to reduce the PURPA contract length from 20 years to 3 years but was denied.[119]

On the flip side, in June 2019, Washington State increased its contract length from 5 years to 12-15 years.[120]

4.1.4 Summary of Witnesses Commenting on PPA and NOC Documents

The main witnesses for the PPA and NOC form terms and conditions were Mr. Levitas for SBA and Mr. Wheeler (Standard Offer PPA) and Mr. Johnson (Large QF PPA and NOC form) for Duke. In addition, there were other witnesses who touched on issues related to PPAs and NOCs but did not make proposed markups to the documents. These witnesses are:

- Jon Downey, Southern Current, representing SBA
- Hamilton Davis, Southern Current, representing SBA
- Brian Horii, E3, representing ORS
- Robert Lawyer, representing ORS

---

118 Public Service Commission of Utah, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities – Docket No.15-035-53 Order" Issued January 7, 2016 https://pscdocs.utah.gov/electric/15docs/1503553/27127015035530.pdf

119 "25. The Commission denies RMP's Application for authority to amend Schedules 37 and 38 to reduce the contract term of its PURPA PPAs with QFs from 20 years to three years. The Commission concludes that RMP failed to meet its burden to demonstrate that the proposed modification of the Wyoming PPA contracts is reasonable, will solve an alleged system-wide problem, and is in the public interest of Wyoming ratepayers."

Public Service Commission of Wyoming, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities," Docket No. 20000-481-EA-15 (Record No. 14220), June 23, 2016.

Similar decisions reached by the Wyoming PSC for the other utilities, notably PacifiCorp.

120 Washington State Legislature, Chapter 480-106-050
https://apps.leg.wa.gov/wac/default.aspx?cite=480-106&full=true

- Rebecca Chilton, representing Johnson Development Associates, Inc.
- George Brown, Duke

4.1.5 *Summary of Issues*

Duke and SBA each provided direct, rebuttal (Duke) and surrebuttal (SBA) testimony as it relates to the Standard Offer PPA, Large QF PPA and Notice of Commitment (NOC) to Sell Form. They provided oral testimony at a hearing held before the Commission October 21-22, 2019. SBA also provided testimony in the Dominion hearing held Oct 14-15, 2019 during which Duke's terms and conditions were cited on occasion.

4.1.5.1 *Resolved Issues*

The parties have come to a negotiated agreement on several issues originally cited in Mr. Levitas' Direct Testimony as warranting revision. This is viewed by Power Advisory as evidence that these negotiated terms are fair and reasonable. These included the following organized by the document to which they refer.

Standard Offer PPA

Requests accepted by SBA:

- Agreed to Material Alterations subject to two conditions: (1) Duke's consent to requested material alterations will not be unreasonably withheld, conditioned or delayed and (2) changes are made prospectively not retroactively.

Requests accepted by Duke:

- Accepted the first condition above (but not the second one)
- At the request of ORS, agreed to remove "estimated annual energy production" from its definition of Existing Capacity which was included in Material Alterations. A number of other points were negotiated between SBA and Duke as a result of the inclusion of this term (estimated annual energy production) but became a moot point after Duke agreed to remove it.
- Agreed to adopt a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment.

Large QF PPA

Requests accepted by SBA:

- Accepted proposal for liquidated damages equal to the average annual estimated capacity payments under the Agreement over the Term for up to 15 MW and $10,000/MW-AC thereafter.

Requests accepted by Duke:

- Agreed to adopt a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment.
- Agreed to replace PPA termination for failure to comply with confidentiality or publicity provisions of the PPA with liquidated damages but maintaining all legal remedies available as need be.
- Agreed to enter into a new or modified PPA agreement that is consistent with the Commission's Order.
- Agreed to allow force majeure as a reason to extend the COD Milestone Date.
- Agreed to set the COD Milestone Date at 90 days after the Interconnection Facilities and System Upgrades In-Service Date and allow for day-to-day extensions to account for any delays not caused by the Seller QF.

Notice of Commitment (NOC) to Sell Form

Requests accepted by Duke:

- Agreed to provide 10 Business Day cure period for Section 6.iii of the form (related to PPA termination for missing COD date, ceasing to have site control, or ceasing to be certified as a QF with FERC)
- Agreed that remove Section 8 ("8. Seller will make the Company whole for any damages or expenses arising from Seller's breach of any warranty, representation, or covenant in this Notice of Commitment.

A summary of the issues that have not been resolved are shown below. These unresolved matters are reviewed in the next sections of this chapter along with Power Advisory's recommendations for resolution.

4.1.5.2 *Issues Not Resolved*

Standard Offer PPA issues not resolved include:

- Material alterations – retroactive vs. prospective
- 30-month in-service date following rates approval

Large QF PPA issues not resolved include:

- Facilities Study Agreement (FSA) a condition of signing a Large QF PPA
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC
- Surety Bonds as a permissible form of performance assurance

Notice of Commitment (NOC) to Sell Form issues not resolved include:

- All required permits and land-use approvals a condition of LEO formation
- 365 day in-service requirement following LEO formation
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC

4.2 Standard Offer PPA (≤ 2 MW)

4.2.1 Material Alterations – Retroactive vs. Prospective

Duke seeks to clarify that they may discontinue purchases from the QF and/or terminate a QF's PPA in the event that there is a material alteration.[121]

In his rebuttal testimony, Mr. Wheeler defines Material Alteration as follows:

> "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation,
>
> (i) the addition of a Storage Resource;
>
> (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), or generating capacity (or similar term used in the Agreement) (the "Existing Capacity"), or
>
> (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%), shall not be considered a Material Alteration."[122]

[121] Duke Wheeler Direct, p.21.

[122] Duke Wheeler Rebuttal, p.7.

Thus, absent any necessary repair and replacement that doesn't affect the DC or AC rating by +/- 5%, which is allowable, any increase in the facility's DC or AC rating, or any decrease in the facility's DC or AC rating by more than 5% requires the consent of Duke. Also, consent is required for the addition of a Storage Resource. If consent is not given, the QF's PPA would be terminated and they would be able to enter into a new PPA with the then-current avoided cost rate.

Mr. Wheeler argues against the QF being allowed to violate the +0/-5% tolerance during the development process saying that by the time a PPA is executed that the general parameters of the facility should be known. If circumstances cause significant material changes to the facility, the PPA should be subject to review."[123]

Initially, Mr. Levitas argues against a QF having to get Duke's consent for any Material Alterations. However, in his surrebuttal testimony he accepts Duke's position on these issues subject to two modifications as follows:

> "[1] Duke's Terms and Conditions need to provide that Duke's consent to requested material alterations will not be unreasonably withheld, conditioned or delayed. Duke has agreed to a similar condition in its Large QF PPAs.
>
> [2] The proposed terms and conditions must be applied only prospectively to new PPAs and not be made applicable to existing PPAs. (It is not clear whether Duke is asking the Commission to modify existing PPAs to incorporate its proposed new terms and conditions, but doing so would be highly problematic for existing QFs and their financing parties and of questionable legality.)"[124]

In hearing testimony, Mr. Wheeler says that Duke agrees to Mr. Levitas' first condition, but not the second. Duke intends on modifying the terms and conditions for <u>all existing and future</u> Standard Offer PPAs. Mr. Wheeler comments:

> "Mr. Levitas states the terms and conditions should only be applied prospectively to the new PPAs. I disagree with Mr. Levitas since it contradicts existing long-standing language in the rate update section of Schedule PP in Provision 1(B) of the terms and conditions. This language was repeated to be clear that all provisions of the company tariffs are subject to review and revision by the Commission and, upon approval, would apply to all Standard Offer QF purchases. The only exception that's identified in this language is that any levelized rates will not change during the contract term offered to the QF, the price certainty necessary to secure financing."[125]

---

[123] Duke Wheeler Rebuttal, p. 19.

[124] SBA Levitas Surrebuttal, p. 11.

[125] Hearing Vol 1, p. 262 (Duke Wheeler).

In hearing testimony, Mr. Levitas objected to Mr. Wheeler's suggestion of revising all Standard Offer PPAs with the new terms and conditions stating, indicating it would be terrible public policy, and if that is Duke's position, then he would object to the Material Alterations clause in its entirety:

> "The second condition on our willingness to agree to these very extensive changes is that they must be applied only prospectively to new PPAs, and not be made applicable retroactively to existing PPAs. Mr. Wheeler pointed out, in his sur-surrebuttal, if you will, that you have adopted language in the past that does provide that, when you approve changes to the standard offer forms, that they may be made applicable retroactively, so that -- that language does exist, but that doesn't obligate you to make them applicable retroactively, and I would submit to you that, where you have many contracts that are in place today based on the -- the laws and -- and the terms of these conditions that were in effect at the time, to adopt this kind of wholesale change to a document, and then incorporate that -- all of that -- those changes retroactively to existing contractual relationships is terrible public policy. And, while -- as I said, we don't oppose these types of changes being made going forward, if your view was that we're -- if we make them going forward, we're also going to make them retroactively, and our position would be don't make them at all."[126]

<u>Power Advisory Opinion</u>

The Commission will have to decide on balancing Duke's goal which is to apply the new terms and conditions retroactively to all existing Standard Offer QF contracts with SBA's goal of only applying them to new PPAs. Though it doesn't obligate the Commission to do so, there is a provision in the existing Standard Offer that allows for revision of the existing contracts. Provision 1(b) reads as follows:

> **"**Application of Terms and Conditions and Schedules - All Purchase Agreements in effect at the effective date of this tariff or that may be entered into in the future, are made expressly subject to these Terms and Conditions, and subject to all applicable Schedules as specified in the Purchase Power Agreement, and any changes therein, substitutions thereof, or additions thereto lawfully made, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract or by order of the state regulatory authority having jurisdiction (hereinafter "Commission")."[127]

The clause "…provided no change may be made in rates or in essential terms and conditions of this contract…" would seem to indicate that there is protection for the seller.

---

[126] Hearing Vol 1, p. 311-312 (SBA Levitas).

[127] Duke Energy Carolinas Schedule PPA Terms and Conditions, effective July 1, 2016, Provision 1(b) https://etariff.psc.sc.gov/Attachments/tariffFile/492cc0bb-7d8c-437e-b9d9-b8ad65eab2cf

The problem with changing contract terms and conditions retroactively is that it can have a chilling effect on existing and future financing, as the lender community, which requires certainty, doesn't know what to expect in the way of changes down the road once it agrees to financing. It's not only the lender community but the developer community as well.

Two things are not clear:

1. Whether Duke would identify existing operating projects that have made changes in the past that are now deemed Material Alterations and as a result, terminate the PPA. Power Advisory believes that if the Commission does allow Duke to adopt these terms and conditions retroactively, then Duke's ability to terminate should only be on Material Alterations made in the *future*, not the past.
2. Whether Duke is referring to the Material Alteration terms/conditions only or <u>all</u> terms/conditions that are being revised in the Standard Offer as part of this proceeding.

From a commercial reasonableness standpoint, Power Advisory would argue that making changes to the terms and conditions of a contract retroactively is not commercially reasonable as it sets a potentially dangerous precedent. Rather, they should only be applied prospectively to new PPAs.

4.2.2 30-month In-service Date Following Rates Approval

Mr. Levitas recommends removing the following paragraph that terminates the PPA after 30 months following the date of the order initially approving the rates selection:

> "Company at its sole discretion may terminate this Agreement on , 20__ (30 months following the date of the order initially approving the rates selection shown above which may be extended beyond 30 months if construction is nearly complete and Seller demonstrates that it is making a good faith effort to complete its project in a timely manner) if Seller is unable to provide generation capacity and energy production consistent with the energy production levels specified in Provision No. 1.4 above. This date may be extended by upon mutual agreement by both parties."[128]

Mr. Levitas says that the 30 month rule has been a problem in North Carolina. In North Carolina, there have been long waits for interconnection. On one occasion, Duke voluntarily agreed to extend eligibility for the rates and on another it was directed to do so by the North Carolina General Assembly. A similar situation has occurred in South Carolina, where many projects that established LEOs under the prior standard offer rate schedule were not able to begin deliveries of

[128] SBA Levitas Direct, Levitas-1 Section 3: Initial Delivery Date.

power within 30 months after those rates were approved, solely because of interconnection delays.[129]

In rebuttal testimony, Mr. Wheeler says that this provision was adopted in 2016 so as to avoid QFs getting "stale" rates. Hypothetically, this would allow a QF to enter into a Standard Offer PPA in 2019 and begin selling its output to the Companies in 2025, for a period ending in 2035, at rates set in 2019. This would be unjust.[130]

Duke says that if the QF is unable to get the current avoided cost tariff, they can always get the next one.

In hearing testimony, Mr. Wheeler states:

> "Mr. Levitas' proposal would significantly extend the length of the time that can pass after QFs lock into avoided cost rates until they begin delivering power to the grid. Moreover, the language in the tariff currently provides QFs an extension if they aren't delivering power within the 30 months but their construction is nearly complete and they demonstrate a good-faith effort to complete their project in a timely manner."[131]

In hearing testimony, Mr. Levitas states:

> "For the standard offer, in my direct testimony, as you heard earlier, I recommended removing the requirement in the Duke proposed PPA that a QF be placed in service within 30 months of the Commission's approval of the standard offer tariff. In my surrebuttal testimony, I state that SBA doesn't object to this outside in-service date provided it is linked to the interconnection facilities and network upgrades in-service date, as Duke has agreed to with respect to Large QF PPAs. So there's a COD deadline under contract that is extended based on interconnection delays. I'm suggesting the same thing apply with respect to the Standard Offer PPA."[132]

Power Advisory Opinion:

Customers need reasonable protections to avoid "stale" rates and completion of the project in a timely manner. However, Mr. Wheeler does not address Mr. Levitas' issue of the lengthy interconnection process. Since the in-service date of the interconnection facilities and network upgrades for the QF is out of the QF's hands, it's only fair that the QF be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection facilities. Duke has already agreed to this for the Large QF PPA. There is no reason why this shouldn't also be the case for the Standard Offer and Duke itself offers no reason. In fact,

---

129 SBA Levitas Direct, p. 28-29.

130 Duke Wheeler Rebuttal, p. 10.

131 Hearing Vol 1, p. 258-259 (Duke Wheeler).

132 Hearing Vol 1, p. 309-310 (SBA Levitas).

Mr. Brown of Duke acknowledges in hearing testimony that the QF should not be responsible for delays in interconnection:

> "Q. So who bears the risk that the project will fall behind schedule, the QF or the ratepayer?
>
> A (BROWN) Generally speaking, I would say -- it depends if it's because of something that the utility is doing on our side, we're unable to connect it, I would say the QF is not responsible for that."[133]

Currently, Duke provides extensions to the QF if the QF's construction is nearly complete and they demonstrate good faith effort to completing their project in a timely manner but does not address the issue of completing their own network upgrade construction in a timely fashion.

4.3 Large QF PPA (>2 MW)

4.3.1 Facilities Study Agreement (FSA) a Condition of Signing Large QF PPA

In his rebuttal testimony, Mr. Johnson says that Duke will require the QF to have returned a Facilities Study Agreement before signing a PPA which will demonstrate commercial viability of their project. This is in response to agreeing to extend the COD deadline due to interconnection delays. Specifically, Mr. Johnson states:

> "To ensure QFs are not prematurely entering into PPAs as a result of this added flexibility to the COD Milestone [referring to extensions due to interconnection delays], the Companies have also revised the Large QF PPA to require that, in order to enter into the Large QF PPA, a QF must have executed and returned the Facilities Study Agreement to the Companies under the South Carolina Generator Interconnection Procedures."[134]

In hearing testimony, Mr. Johnson states:

> "The issue has to do with when a QF can enter into a PPA. As described in my rebuttal testimony, we believe it is appropriate for a QF to enter into a PPA after it sends a Facilities Study Agreement (FSA) back to the utility. At this point in time, the QF has insight into its interconnection and system upgrade costs and can evaluate the commercial viability of the project. In order to accommodate Witness Levitas' request to create a flexible commercial operation date, adding this provision was also important to Duke to ensure QFs are not prematurely entering into PPAs as a result of this added flexibility. Witness Levitas advocates that a QF should be able to enter into a PPA once it has been an

[133] Hearing Vol 2, p. 215 (Duke Brown)

[134] Duke Johnson Rebuttal, p. 11.

> interconnection customer for one year; however, as I describe in my rebuttal testimony, without knowing interconnection costs and an estimate of time frame to achieve COD, the QF facility is not to the point in the development process of knowing whether the generating facility is commercially viable."[135]

In hearing testimony, Mr. Levitas quotes from his surrebuttal testimony. He points out that Mr. Johnson has not adequately addressed his proposal that the QF be able to form a LEO or execute a PPA within one year of filing its interconnection request. Otherwise, Duke is in a position to frustrate or control the QF. His surrebuttal testimony states:

> "…as Witness Johnson observes, deferring LEO/contract formation until the FSA has been signed provides both the developer and the utility with a better sense of project viability and moves the establishment of the contract price to a point closer to commercial operation. However, Witness Johnson fails to recognize the purpose served by my proposal that, in the alternative, the QF be able to form a LEO or execute a PPA within one year of filing its interconnection request if the utility has not completed the System Impact Study (or using Duke's proposal, if it has not yet been presented with a Facilities Study Agreement to execute). In the absence of such an alternative, the utility could potentially control and frustrate the QF's LEO formation, which has been expressly prohibited by FERC and reaffirmed in the NOPR. As I pointed out in my direct testimony, the North Carolina Utilities Commission, with Duke's consent, has adopted exactly this sort of approach. In sum, I am comfortable with Duke's proposed requirement that a signed FSA be a condition of LEO formation or PPA execution, provided that there is an alternative eligibility criterion based on time from the interconnection request. I continue to believe that one year is a reasonable interval given the time frames set forth under the Interconnection Procedures, but if Duke believes the one-year time frame I proposed is unreasonable in some circumstances, SCSBA would be willing to discuss alternatives."[136]

<u>Power Advisory Opinion</u>

Mr. Johnson has not addressed Mr. Levitas' point that the utility can potentially control or frustrate the QF if the QF has not received a System Impact Study within one year from the time of Interconnection Request since the QF will not know its interconnection costs, albeit preliminary, before LEO formation. In the extreme case, if Duke were to delay delivery of the System Impact Study (SIS) for an indefinite period, then the QF would never be able to sign a PPA with the knowledge of what its interconnection costs would be. Controlling or frustrating the QF to form a LEO is prohibited by FERC.[137] Power Advisory agrees that Duke should be required to provide a System Impact Study within a timely manner to the QF from the time of Interconnection Request

---

[135] Hearing Vol 1, p. 267-268 (SBA Levitas).

[136] SBA Levitas Surrebuttal, p. 9.

[137] See paragraph 23 in the Montana ruling: 157 FERC ¶ 61,211, Docket No. EL7-5-000 https://www.ferc.gov/whats-new/comm-meet/2016/121516/E-7.pdf

(whether that time frame is one year or a period of time that is mutually agreeable to the buyer and seller). If the SIS is not provided in a timely manner, then the requirement that the QF execute and return a Facilities Study Agreement (FSA) in order to sign a PPA should be lifted.

While Mr. Johnson argues that an FSA is required to demonstrate commercial viability, it's nonetheless more important that the utility not be permitted to control or frustrate QF development through unreasonable delays in interconnection. If Duke were to deliver SISs in a timely manner then this would be a moot point – Duke would achieve its stated goal of only having projects that are commercially viable and the QF community would achieve its stated goal of not being unfairly delayed.

4.3.2 Offramp Should Interconnection Facilities & Network Upgrades Exceed $75,000/MW

In direct testimony, Mr. Levitas expresses SBA's point of view as follows:

> "I think that the PPA should include a right of Seller to terminate the PPA without liability if the interconnection facilities and network upgrades required for the facility to be interconnected to Duke's system exceed $75,000 per MW per AC. Given the QFs' total lack of control over and visibility into Duke's interconnection costs, and the extremely high interconnection costs that have been quoted to many QFs, it is reasonable to provide this limited off-ramp from the obligations."[138]

In rebuttal testimony, Mr. Johnson does not agree with SBA's proposal to be able to walk away from a commitment if system upgrade costs exceed $75,000 per MW AC. First, it allows the QF to make a binding commitment to sell that it could walk away without any liability. Second, Mr. Levitas doesn't give any basis for the $75,000 / MW AC figure.

> "When considered together, the result seems to be that if the QF's System Impact Study Report estimates interconnection costs in excess of $75,000 per MW of the Facility's Nameplate Capacity, the QF could elect to enter into a Notice of Commitment knowing at the time it purportedly made a binding commitment to sell that it could walk away without any liability."

> "Mr. Levitas also provides no basis for this arbitrary $75,000/MW threshold for the costs of interconnection facilities and system upgrades, which will be increasingly exceeded as more and more generators interconnect to the grid. While I am not an expert on the interconnection process, it is my understanding that it is increasingly routine for a two (2) MW generator to exceed $150,000 in total interconnection facilities and system Upgrades and for transmission connected generators 20 MW to 50 MW to exceed the $1.5 million

[138] SBA Levitas Direct, p. 19.

> to $3.75 million in interconnection facilities and system Upgrades. Because a QF exceeding these thresholds would essentially be absolved from its LEO commitment and allowed to walk away without liability, Duke does not support this proposal."[139]

In his surrebuttal testimony, Mr. Levitas agrees to remove the offramp as long as the System Impact Study is completed within a year from the time of interconnection request. Mr. Levitas says:

> "…the utilities have the ability to take my proposed condition precedent out of play by completing the System Impact Study within a year, which is much longer than the time provided for in the Commission's interconnection procedures."[140]

In hearing testimony, Mr. Johnson reiterates his point:

> "The issue has to do with whether the QF should be allowed to terminate the PPA, because its interconnection costs are more than $75,000 per megawatt. My rebuttal testimony explains that this is an unnecessary provision, because under Duke's proposal, the QF would already know its interconnection costs before entering into a PPA. But, more importantly, this option would not provide for a binding commitment by a QF, as it could terminate their PPA without penalty."[141]
>
> In hearing testimony, Mr. Levitas summarizes his direct and surrebuttal testimony and adds that Dominion has agreed to the provision of allowing the QF to terminate their PPA without penalty if interconnection costs exceed $75,000/MW-AC.[142]

<u>Power Advisory Opinion</u>

Mr. Johnson does not address Mr. Levitas' point that the timeliness of the System Impact Study would make the offramp for high interconnection costs a moot point. Experience elsewhere indicates that interconnection costs tend to increase with higher penetration rates of such resources. The risk to the QF of entering into a PPA and then facing either interconnection costs that make the project unviable or significant liquidated damages because of termination is unreasonable.

As a result, Power Advisory believes that Duke should either: (1) provide the System Impact Study within 1 year of interconnection request (or an amount of time that is mutually agreeable between the buyer and seller) or (2) allow an offramp to the QF. Dominion has accepted the offramp provision.

---

[139] Duke Johnson Rebuttal, p. 41.

[140] SBA Levitas Surrebuttal, p. 4.

[141] Hearing Vol 1, p. 268 (Duke Johnson).

[142] Hearing Vol 1, p. 306-307 (SBA Levitas).

Duke maintains a similar stance on this issue as it did for the issue pertaining to the FSA being a requirement for a QF to enter into a PPA. Again, the issue is moot if Duke is able to process System Impact Studies in a timely manner. If Duke can process the SIS in a timely manner, both sides will have achieved their stated goals: Duke's of not wanting to allow QFs the offramp for expensive interconnection costs, and the QF community's of not wanting to enter into a PPA and potentially face interconnection costs that could make a project unviable.

4.3.3 Surety Bonds as a Permissible form of Performance Assurance

In surrebuttal testimony, Mr. Levitas states that Duke does not allow the use of surety bonds as a permissible form of performance assurance. In contrast, Dominion's proposed PPAs do allow for the use of surety bonds and include a commercially reasonable form bond for this purpose. Mr. Levitas recommends Duke doing so as well.[143]

In hearing testimony, Mr. Johnson offers two reasons as to why Duke doesn't offer surety bonds as a form of performance assurance: (1) feedback from the seller community while developing the CPRE Tranche 1 PPA and (2) Duke has never allowed a surety bond in any previous PPA.

> "Mr. Levitas suggests through surrebuttal that Duke should allow the use of a surety bond as a permissible form of performance assurance. The company's considered comments from the solar community on this issue when developing the PPA that was used for CPRE, and do not believe that a surety bond would be a permissible form of performance assurance. Duke has never allowed a surety bond in any previous PPA and Mr. Levitas offers no reason why this is reasonable."[144]

In cross-examination, Mr. Johnson says that surety bonds are harder to collect on than cash, but does not offer a reason as to why Dominion would offer a surety bond as an eligible form of performance assurance, indicating that this is not his area of expertise. Whereas Duke offers three forms of performance assurance – cash, letter of credit and a guarantee – Dominion offers the same three, but also offers surety bonds.[145]

In further cross-examination, Mr. Wheeler indicates that Duke made a determination several years ago to drop surety bonds as a form of performance assurance because they found that in some cases, the QF didn't renew the surety bond for the life of the contract.[146]

<u>Power Advisory Opinion</u>

---

[143] SBA Levitas Surrebuttal, p. 4.

[144] Hearing Vol 1, p. 278 (Duke Johnson).

[145] Hearing Vol 1, p. 281-282 (Duke Johnson).

[146] Hearing Vol 1, p. 283-284 (Duke Wheeler).

Power Advisory believes that Duke should be able to determine the appropriate security for performance assurance. They already allow three options including cash, letter of credit and a guarantee which we believe is enough. Duke looked at this issue several years ago and made a determination that surety bonds posed more risks than the other options.

4.4 Notice of Commitment to Sell Form

4.4.1 All Required Permits and Land-use Approvals a Condition of LEO Formation

In his direct testimony, Mr. Johnson proposes that the QF must first secure all required permits and land use approvals before LEO formation as a means of showing project viability and refers to similar requirements in Montana and Minnesota.

In his direct testimony, Mr. Levitas objects to the fact that a pre-condition of LEO formation is that the QF has to first secure all required permits and land-use approvals. Mr. Levitas indicates that obtaining environment permits and land-use approvals can be an expensive and time consuming process, sometimes costing in the hundreds of thousands of dollars. It is unreasonable to expect a QF to incur these expenses until it has secured a price for its output so that it can in turn secure financing for the project.[147]

Mr. Levitas goes on to say that the Standard Offer PPA is silent on this topic and that for the Large QF PPA, it expressly states that permits are obtained <u>after</u> the PPA is signed. So there is no reason for LEO formation to be more onerous than the PPA.

In his rebuttal testimony, Mr. Johnson's main points are: [148]

- In order to show commercial viability and financial commitment to construct a QF generator, the QF must have site control
- This dictates that the QF must have necessary environmental permits or other zoning approvals
- QFs have the option of entering into a Large QF PPA if they would like to have the in-service date extended for delays in interconnection, but does not offer the same for LEO formation
- There should be no legal impediment to the QF constructing the project at the time it commits to sell and deliver the output under the Notice of Commitment Form
- Minnesota and Montana have similar requirements:

> "As I mentioned briefly in my Direct Testimony, both Montana and Minnesota have explicitly found that obtaining site permits are an appropriate prerequisite for determining

[147] SBA Levitas Direct, p. 25.

[148] Duke Johnson Rebuttal, p. 34-35.

> the date a LEO is established. In Montana, the Public Service Commission, through its PURPA-implementing administrative rules, instructs that a LEO is established when a QF "has obtained and provided to the purchasing utility written documents confirming control of the site for the length of the asserted legally enforceable obligation and permission to construct the qualifying facility that establish, at a minimum . . . (ii) proof of all required land use approvals and environmental permits necessary to construct and operate the facility." Likewise, the Minnesota Public Utilities Commission ("Minnesota PUC") has many times considered the existence of site permits, or lack thereof, as evidence relevant to the establishment of a LEO."

In his surrebuttal testimony, Mr. Levitas re-states that it is not reasonable to require QFs to obtain all environmental permits and land use approvals without having firm pricing and that Duke has never made such requirements a pre-condition for a PPA.[149]

At the hearing, Mr. Johnson states:

> "The issue that's still in contention is the requirement that a QF must secure all environmental permits and land-use approvals, in order to execute the Notice of Commitment Form. I believe that this is a reasonable requirement that demonstrates a commitment by the QF to develop the project and sell power to the utility." [150]

At hearing testimony, Mr. Levitas states:

> "I explained in my direct testimony why it is not reasonable to require QFs to obtain all environmental permits and land use approvals without having firm pricing and note in my surrebuttal testimony that Duke has never made such requirements a pre-condition of executing a PPA, and does not propose to do so in this proceeding." [151]

<u>Power Advisory Opinion</u>:

Both sides make good points. Duke only wants viable projects to form LEOs and identifies other states (Minnesota and Montana) that similarly require permits before LEO formation. Mr. Levitas indicates the costly nature to the QF of obtaining all permits without even knowing its avoided cost rate. He also identifies the contradiction that Duke has never required permits in advance of signing a Large QF PPA.

While Mr. Johnson referred to Minnesota and Montana as two states that require permits prior to LEO formation, Power Advisory also found states that did not have this requirement. For example,

---

[149] SBA Levitas Surrebuttal, p. 10.

[150] Hearing Vol 1, p. 271 (Duke Johnson).

[151] Hearing Vol 1, p. 309 (SBA Levitas).

in Washington, the published Contracting Procedures only require a description of and anticipated timeline for acquiring any outstanding permits but do require the permits themselves. The requirement is described as follows:

> "List of acquired and outstanding Qualifying Facility permits, including a description of the status and timeline for acquisition of any outstanding permits."[152]

This is a lower bar than actually requiring that all permits be in hand.

Power Advisory believes that since SBA has agreed to the 365 day in-service date requirement (conditional on obtaining a System Impact Study (below)), that QFs be allowed to secure permits after formation of a LEO, so as to balance the two issues. As in the case of Washington, a list of the acquired and outstanding permits could be required to be outlined.

This makes it consistent with the Large QF PPAs which do not require permits be obtained before execution. The QF already has to meet the requirement of being in service within 365 days or risk termination and resulting liquidated damages. This requirement alone will motivate QFs to move forward with viable projects only.

4.4.2 365 Day In-service Requirement Following LEO Formation

In Duke's direct testimony, they require that the QF place its facility in service within 365 days of executing the Notice of Commitment (NOC) form.

In his direct testimony, Mr. Levitas objects to this requirement. Mr. Levitas says this would impose "unreasonable obstacles" to LEO formation which is in violation of FERC precedent. It's unreasonable because the interconnection and the construction process in South Carolina is currently taking 3 years. Smaller, less complicated QFs may be able to achieve COD within 365 days, but larger complicated ones cannot since their timelines are longer.

Specifically, Mr. Levitas says:

> "QFs must be able to secure pricing before they can incur major development expenses, secure financing, and construct the project. While many QFs can complete the development cycle within a year, larger and more complex QFs may not be able to do so.
>
> But more significantly, Duke's interconnection study and construction process in South Carolina has been taking on the order of three years. So Duke's proposed 365-day in service requirement is tantamount to saying that no QF could ever form a non-contractual LEO that it could comply with. Even more problematic is the fact that there is no point in

[152] Avista, "Schedule 62 Appendix A - Contracting Procedures", pursuant to WAC 480-106-030(2). https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/wa/rate-requests/schedule-62-filing.pdf?la=en

> the interconnection process at which a QF has any guarantee that it will achieve interconnection by a specific date, since Duke views the deadlines under the SCGIP and even in Interconnection Agreements as essentially unenforceable. In fact, a QF often has no idea how long it will take to achieve interconnection, and therefore commercial operation. It would be completely unreasonable to require a QF to predict when it will be 365 days or less from commercial operation."[153]

In his surrebuttal testimony, Mr. Johnson responds to SBA by saying that 365 days is not too onerous and makes the following main points: [154]

- QFs should not be able to lock into avoided cost rates indefinitely
- The QF is making a binding commitment to construct the Facility and achieve commercial operation when it submits the Notice of Commitment Form and establishes a LEO
- Duke suggests that execution of a Large QF PPA would alleviate much of Mr. Levitas' concerns regarding failure to achieve COD since Duke has accepted Mr. Levitas' proposal to set the COD Milestone at 90 days after the Interconnection Facilities and System Upgrades In-Service Date and allow for day-to-day extensions to account for any delays not caused by the Seller QF
- QFs by definition take risks and the risk that the QF doesn't achieve COD is one risk that it is taking
- Idaho, New Mexico and Texas are three examples of where the in-service date requirement is 365 days or less following formation of a LEO

In his surrebuttal testimony, Mr. Levitas is willing to withdraw its objection to the 365 day in-service requirement if the COD deadline is extended to account for additional time required for the utility to complete required Interconnection Facilities and Network Upgrades.[155]

At the hearing, Mr. Johnson states:

> "As described in my testimony, it's reasonable to require a QF to deliver power within 365 days after executing a Notice of Commitment Form. To ensure that QFs are not locking into prices or into rates for an extended period of time, and then requiring customers to pay for those stale rates on those purchases. My testimony points out that the 365-day period is less stringent than the requirements in other states like Texas and New Mexico."[156]

---

[153] SBA Levitas Direct, p. 26.

[154] Duke Johnson Surrebuttal, p. 23-29.

[155] SBA Levitas Surrebuttal, p. 7-8.

[156] Hearing Vol 1, p. 270-271 (Duke Johnson).

At the hearing, Mr. Levitas states:

> "In my direct testimony, I objected to Duke's requirement that the QF be capable of being placed in service within 365 days as a condition of LEO formation using the NOC form. However, in my surrebuttal testimony, I state that SCSBA is prepared to withdraw that objection if the deadline is extended to account for additional time needed by the utility to complete required interconnection facilities and network upgrades. I note that the DESC NOC form contains such a provision. I would also note that this is similar to Duke's Large QF PPA term which extends COD based on interconnection delays." [157]

Power Advisory Opinion:

Mr. Johnson doesn't address Mr. Levitas' proposal to remove his objection if the deadline is extended to account for additional time needed by the utility to complete required interconnection facilities and network upgrades except to say that the QF could opt to enter into a Large QF PPA where that provision exists. However, that doesn't help the QF if it feels the utility is refusing to enter into a PPA (which is why it would need to go the LEO route in the first place).

As in the case of the 30-month in-service requirement following rates selection for the Standard Offer, the Commission must balance the goal of the utility to keep the timelines relatively short, while also allowing the QF a legitimate chance to meet its deadlines.

In conducting additional research on in-service requirements following LEO formation, Power Advisory has found that there are other states where the allowable time is longer than 365 days from LEO formation. The two most recent rulings were in Washington State (June 2019)[158] and Oregon (August 2016).[159] Thus, while Duke has identified three states with relatively short deadlines, other states have longer deadlines. Thus, while Duke has identified three states with relatively short deadlines, other states have longer deadlines.

In sum, Power Advisory believes that the QF should be required to be in-service within 365 days of forming the LEO but that the COD date should be extended to 90 days following completion of the utility upgrade work. Thus, the utility must bear some of the responsibility to ensure that the timeline is reasonable. Otherwise, in the extreme case, it would be possible for them to simply delay the upgrades until the QF can no longer meet its deadline.

---

[157] Hearing Vol 1, p. 308 (SBA Levitas).

[158] Washington Administrative Code (WAC) 480-106-050, Section 4.
https://apps.leg.wa.gov/wac/default.aspx?cite=480-106&full=true

[159] Oregon Standard Power Purchase Agreement (New QF), approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3.
https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_New_Firm_QF_And_Intermittent_Resource_with_MAG.pdf

4.4.3 Offramp Should Interconnection Facilities & Network Upgrades Exceed $75,000/MW

This is similar to Section 4.3.2 and Power Advisory believes it should be dealt with the same way.